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Coal		Coal/Liquid Mixtures	21D	
Nitrogen Oxides		Particulate	07B	
Sulfur Dioxide				
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by

J. H. E. Stelling and S. J. Call
Radian Corporation
3024 Pickett Road
Durham, North Carolina 27705

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EPA Project Officer: Robert E. Hall

Industrial Environmental Research Laboratory
Environmental Research Center
Research Triangle Park, North Carolina 27711

INDUSTRIAL ENVIRONMENTAL RESEARCH LABORATORY
OFFICE OF RESEARCH AND DEVELOPMENT
U.S. ENVIRONMENTAL PROTECTION AGENCY
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ABSTRACT

This report summarizes the existing data base on nitrogen oxides (NO_x), sulfur dioxide (SO_2), and particulate matter emissions from combustion sources burning coal/liquid mixtures (CLMs). It also gives available emissions data for the various trace elements, and identifies control techniques that can reduce the emissions of the above pollutants. These techniques are assessed for their efficiency to reduce emissions from CLM combustion to levels representative of oil firing.

Recognizing that environmental considerations must be taken into account in any evaluation of fuel conversion to CLM, this report identifies and asseses the effectiveness of currently available methods of controlling the release of criteria and non-criteria (trace elements) pollutants from the combustion of CLMs.

In addition to the technical evaluations, economic evaluations of control technologies are presented. Capital costs, operating expense, and overall lifecycle costs are presented and discussed. Also presented are cost curves that relate cost of use to the pollutant removal efficiency.

Multipoint control capabilities of the selected control technologies are assessed, as well as any secondary pollution problems associated with using a particular control technique. Any particular problems with retrofit applications of the devices are highlighted, and any interferences of the control devices with the combustion process are discussed.

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CHAPTER 1

INTRODUCTION

Coal-liquid mixtures (CLM) such as coal-oil, coal-water, and coal-alcohol are promising alternatives to oil and gas for existing boilers. Interest in coal-liquid mixtures has grown rapidly as boiler operators try to reduce their consumption of oil and expand their use of coal. Coal-oil mixtures (COM) and coal-oil-water mixtures (COW) proved to be successful in full-scale industrial and utility tests and are now on the verge of commercial implementation. Coal-water mixtures (CWM) have been successfully combusted in small test combustion units and full-scale testing is planned for the near future. Coal-alcohol mixtures are not yet well-developed as a slurry fuel; although they may be more expensive than COM and CWM, development of coal-alcohol mixtures as a viable slurry fuel alternative is being continued.

In order to expand the use of coal-liquid mixtures in an environmentally acceptable manner, it is imperative that the environmental aspects of CLM combustion be evaluated. Specifically, it is necessary to determine the potential emissions from sources burning CLMs and to assess the effectiveness of various control technologies in controlling criteria and non-criteria pollutants from CWM combustion.

Radian Corporation has been under contract to the U. S. Environmental Protection Agency (EPA) and the U. S. Department of Energy (DOE) to conduct a study which identifies and assesses the currently available methods of controlling the release of pollutants from CLM combustion. This report deals only with the environmental aspects of CWM combustion and coal-alcohol combustion. The environmental aspects of COM and COW were considered in a previous report by Radian (EPA-600/7-83-040; NTIS PB 83-247247).

In general, PM and NO_x emissions for CLMs will be higher than emissions for oil-only firing. CLMs have higher percentages of ash and nitrogen due to these components in the parent coal used in preparing the CLM. SO_2 emissions may be higher or lower than SO_2 emissions from oil-firing, depending upon the sulfur content of the fuels.

The results of this study suggest that potential emissions can be reduced by using conventional control technologies currently applied to oil- and coal-fired boilers. Particulate matter (PM) emissions can be effectively controlled by ESP or fabric filter. Sulfur dioxide (SO_2) and PM control can be achieved simultaneously using either wet or dry FGD systems. Nitrogen oxides (NO_x) emissions can be reduced by using one or more of several combustion modification techniques or post combustion controls. In addition to these conventional means of control, PM and SO_2 emissions can also be reduced by pre-combustion techniques such as physical coal cleaning and use of naturally occurring low- sulfur, low-ash fuels. Finally, trace elements are best reduced by PM control techniques.

The cost of controls for PM and PM/SO_2 removal may be somewhat higher than when applied to oil-fired boilers. The increased cost is associated with increased PM removal requirements (higher efficiencies) and increased waste disposal requirements, both of which result from the higher ash content of CLMs.

This report presents general information on the technical, environmental, and economic aspects of CLM combustion and conversion of existing boilers to fire CLMs. Because of the site-specific nature of conversions to CWM, the trends presented here should be used only as guidelines.

Background information concerning the use of CWM in existing boilers is presented in Chapter 2. This chapter includes a discussion of the suitability of CLM in existing boilers, candidate boilers likely for conversion, to CLM, regulatory requirements, and economics of CLM combustion.

Chapter 3 focuses on the potential emissions from CLM combustion. It includes a qualitative analysis of emissions as well as data from COM, CWM, coal-alcohol, and coal combustion. The criteria pollutants discussed are particulate matter (PM), sulfur dioxide (SO_2), and nitrogen oxides (NO_x). Non-criteria trace elements discussed are arsenic (As), beryllium (Be), cadmium (Cd), chromium (Cr), nickel (Ni), selenium (Se), vanadium (V), and mercury (Hg). Polynuclear organic matter (POM) are briefly discussed. Chapter 3 concludes with a discussion of some of the control technologies that are applicable to boilers converted to CWM- firing. From this broad discussion of control techniques, several are selected as most promising for further technical and economic study. These technical and economic evaluations make up the remaining chapters of the report.

Chapter 4 presents the environmental impacts of the control technologies selected in Chapter 3. The primary pollutant control capability and secondary environmental impacts of each technology are discussed. The technologies evaluated include pre-combustion control techniques for PM/SO_2, combustion modification for NO_x reduction, and post-combustion controls for PM, PM/SO_2, and NO_x. The effects of each control technique on trace elements and POM emissions are also discussed.

The costs of various control technologies evaluated in Chapter 4 are presented in Chapter 5 of this report. The capital costs, annual O&M costs, annualized costs, impact on steam costs, and cost effectiveness of various control technology retrofitted to a converted boiler are discussed in this chapter. A discussion of CWM fuel costs is also included in Chapter 5.

The cost bases and assumptions used to develop the costs in Chapter 5 are presented in Appendix A.

CHAPTER 2

USE OF COAL-LIQUID MIXTURES AS BOILER FUELS

The development of coal-liquid mixtures as boiler fuels is steadily gaining momentum as the United States and other nations strive to reduce their consumption of oil and natural gas. Recent studies indicate that oil- and natural gas-fired boilers account for over 65 percent of the industrial boiler capacity in the U. S.[1] and about 40 percent of the utility boiler capacity.[2] The costs associated with converting these boilers to complete coal-firing can be prohibitively high. For this reason, many boiler operators are considering the option of burning coal-liquid mixtures such as coal-oil, coal-oil-water, coal-water, and coal-alcohol. Coal-oil mixture (COM) and coal-oil-water (COW) combustion technologies have advanced very rapidly in recent years and are on the brink of full-scale commercialization. The environmental aspects of COM and COW combustion have been presented in a previous report[3] and will not be discussed here.

This report deals with other coal-liquid mixtures — coal-water and coal-alcohol — in which the need for oil is totally eliminated, not partially replaced as with COMs. Coal-water mixture (CWM) technology lags behind that of COM by about 2 to 5 years, but it too appears to be a viable alternative to oil- or gas-firing. Another potential alternative is the combustion of coal-alcohol slurries. However, at this time, methanol is still more costly than oil and natural gas. Thus, there is limited activity in developing this alternative.

This report will focus primarily on coal-water mixture combustion in existing oil- or gas-fired boilers. The report also briefly discusses the coal-alcohol technology and its potential advantages and disadvantages.

This discussion of coal-alcohol mixtures is in Section 2.5. Available emissions data for coal-alcohol mixtures are presented in Chapter 3.

The purpose of this chapter is to provide some necessary background information in the following areas:

- suitability of CWM in existing or new boilers,
- candidate boilers likely for conversion to CWM,
- regulatory requirements for CWM combustion, and
- economics of CWM combustion.

2.1 SUITABILITY OF CWM IN EXISTING OR NEW BOILERS

2.1.1 CWMs: Preparation and Properties

Coal-water mixtures (CWMs), also referred to as coal-water slurries, consist of 65-75 weight percent coal in water with minor percentages of additives. Due to the economics of CWM preparation facilities, it is most likely that these mixtures will be prepared in centralized off-site facilities rather than at the boiler site. Two CWM preparation facilities to be constructed in Virginia are slated to begin operation in mid- to late-1982.[4,5] At least ten slurry fuel producers have the capability of providing CWMs. Some of these producers have been supplying COM and have added CWM to their product mix.[6]

Bituminous coals are most frequently used in the preparation of CWMs but some lignite and subbituminous coals may also be used. The best combustion results are achieved when the volatiles content exceeds 20 percent.[7] Because coals vary widely in ash and sulfur content, only cleaned coals or low-sulfur, low-ash coals will be used in the preparation of CWMs.

Cleaning the coals reduces the variability of the ash and sulfur content so that prepared CWM fuels are of a more consistent quality. The use of cleaned coals or naturally occurring low-ash, low-sulfur coals also minimizes ash, slagging, derating, and environmental problems resulting from combustion.

In preparing a CWM, wet-ballmilling is likely to be the preferred grinding method, although dry hammermilling or ballmilling can be used. The coal is typically ground to 70-80 percent minus 200 mesh but may be ground to 75 percent minus 325 mesh.[8] The desired high solids loading and decreased viscosity can be brought about by utilizing bimodal particle size distributions and slurry additives. The maximum solids loading of slurries occurs when the liquid fills the voids volume (interstices) of the solids. When particles have a bimodal particle size distribution, the finer particles fit into the interstices of the larger particles. Consequently, less liquid is required to prepare a fluid slurry.[9] The viscosity of CWMs ranges from about 450 to 2,000 centipoise, or from a paint-like consistency to that of a thick gel. Conventional pumping methods are adequate to handle CWMs although there may be potential erosion problems.

Developmental work is being performed to incorporate antifreeze agents into CWMs which, without antifreeze, may freeze at about 0°C (32°F). Antifreeze agents may be necessary to avoid potential transportation and storage problems. Adding 6.4 percent methanol to a mixture containing 70 percent coal effectively lowers the freezing point to -18°C (0°F); and adding 11.1 percent methanol reduces it to -40°C (-40°F).[7] The additives used for stability control may also have an antifreeze effect on CWMs.

The addition of methanol as an antifreeze agent also serves to increase the heating value of the CWM fuel. The heating values of CWMs containing 6.4 percent and 11.0 percent methanol are increased by about 1515 kJ/kg (650 Btu/lb) and 2620 kJ/kg (1125 Btu/lb), respectively.

CWMs are much more abrasive than oil and might potentially cause erosion in pipe bends, pumps, valves, and burners. The same problems are faced in using COMs and coal slurry pipelines. Experience with COMs and coal slurry pipelines has shown that erosion can be minimized through the use of cleaned coal, proper material selection, and lowered fuel velocities.[11,11] Additional studies of erosion in CWM system elements is currently being funded by the Department of Energy's Pittsburgh Energy Technology Center (PETC).[4]

Coal-water mixtures were initially greeted with a negative response due to concern about their combustibility and inherent reduction in boiler efficiency. But it has been demonstrated that CWM will burn and without the prohibitive losses to boiler efficiency originally expected. In fact, the boiler efficiency lost due to evaporating the water and raising the vapor temperature to that of the stack gases should be less than 5 percent as compared to pulverized coal firing. Although initial tests required supplemental fuel to sustain combustion, subsequent tests indicate that CWMs will burn stably with no supplemental fuel support.[12]

There was also some concern about the amount of water vapor in the stack gases and the potential for acid condensation. It is true that there will be a higher moisture content in the stack gas for CWM combustion than for coal-only combustion. But CWM flue gas contains less water vapor than natural gas flue gas and about the same amount of water expected from oil-only combustion. Also, estimates indicate that the acid dew point problems associated with CWM firing will not be any worse than those associated with oil firing.[13]

The major drawback to burning CWMs in existing boilers is that the boilers will probably need to be derated due to the low heating value of CWM as compared to oil. CWM combustion requires a larger furnace volume, due to longer residence time requirements, than does oil-only combustion. The amount of derating which will occur is very site specific but most likely ranges from 15 to 50 percent for units combining combustion modifications with boiler modifications.[10] Other boiler modifications will also be needed to alleviate erosion and slagging problems.

2.1.2 Design Requirements for CWM-firing

There are several design features for CWM-fired boilers which differ from conventional oil-, gas- or coal-fired boilers. The design of the fuel handling systems of a boiler to fire CWM is most closely related to that of an oil-fired boiler, since both are liquid fuels. But, the effects of coal combustion characteristics on CWM combustion will demand several design features typically found only on coal-fired boilers.

Tube spacings in coal-fired boilers are generally larger than those in oil-fired boilers which, in turn, are larger than those in gas-fired boilers. Boilers designed for CWM will most likely require tube spacings between the range of those required for oil and coal boilers. Because some ash deposition and ash slagging might occur with CWM combustion, soot blowers should be installed to dislodge the molten ash from heat transfer sections. As mentioned in Section 2.1.1, ash slagging and deposition problems can be minimized by using CWMs containing coal with low-ash content and high ash fusion temperature.

Burner tips made of hardened materials such as tungsten carbide have been successfully used in COM applications. Since CWM and COM have similar abrasive characteristics, tungsten carbide burner tips should also minimize erosion problems in CWM applications. Atomization velocities must also be reduced to alleviate erosion/corrosion problems. The high- pressure mechanical atomizers typically used for oil-firing should be replaced with low-pressure steam or air atomizers for CWM-firing. Some boiler operators may desire the flexibility to burn oil and COM as well as CWM, in which case the burners and atomizers must be designed to suit all of the fuels.

Combustion of CWM requires a larger combustion space relative to oil or COM for the longer residence time needed for complete combustion of coal particles. The residence time required is dependent upon the coal particle size and particle size distribution. Residence time can be reduced by using CWMs with low-ash, low-sulfur content.

CWM-fired boilers must be equipped with bottom ash handling capabilities. The fuel handling system (pumps, piping, valves, and flow measurement devices) should be made of erosion resistant materials appropriate for handling the CWM slurry. Depending upon the stability of the CWM, it might be necessary to equip storage tanks with agitators and temperature controls. And if multi-fuel-firing capability is desired, additional storage facilities might be needed.

Most of the modifications required for CWM conversion are also required for COM conversion. But the cost of retrofitting for CWM is potentially higher than for COM due to the larger percentage of coal in CWM. The heating value of a typical CWM is lower than that of a COM; therefore, more CWM is needed to achieve the same heat release. Thus, extra space and handling facilities for fuel stocks may be required. Retrofitting for COM and CWM are both less costly than retrofit for pulverized coal, however. COM conversion costs are about 46 percent of those for pulverized coal, and CWM conversion costs are about 64 percent of coal conversion costs.[14]

2.2 CANDIDATE BOILERS LIKELY FOR CWM CONVERSION

Several factors must be taken into consideration when deciding whether converting a particular boiler to CWM combustion is feasible. These factors include:

- existing boiler design and fuel fired,
- boiler size, age, and geographical location, and
- applicable environmental regulations.

But the feasibility of converting to CWM is very site-specific and these considerations should not be taken as the only criteria in making a final conversion decision.

2.2.1 Boiler Design and Fuel Fired

Boilers which were originally designed for coal but are now burning oil are the most likely candidates for conversion to CWM because conversion costs should be the lowest. Some existing oil-designed units (now firing oil) were designed for the future use of coal. These units are characterized by liberally-sized furnaces, step V-bottoms, and wide-tube spacings.[14] These oil designed units are more likely candidates for conversion to CWM than are those units designed with no coal capability.

The least attractive candidates for conversion to CWM are natural gas-fired boilers, although such conversion is possible. Furnace sizes and tube spacings are much smaller than those needed for efficient CWM combustion, making conversion costly and difficult.

2.2.2 Boiler Size, Age, and Capacity Factor

No detailed economic analyses of boiler conversion to CWM combustion are presently available. But, as discussed previously, the same kind of modification required to convert to COM firing will be necessary to convert to CWM firing. The most desirable candidates for conversion to coal, CWM, or COM are boilers with long remaining useful life and relatively high capacity utilization factors. Determining which conversion scheme is most desirable requires a complete economic evaluation, considering boiler and combustion modifications required, pollution control devices required, and fuel cost and availability.

All boilers, large or small, will require boiler modification in converting to CWM combustion. The fuel savings realized by such a conversion must offset the modification costs. Greater fuel savings, and, hence, more favorable economics of conversion make large boilers the most likely candidates for conversion. Modifications to boiler internals are also more easily performed on larger boilers.

Not all large boilers are attractive for conversion, however. Large utility boilers which must operate at close to full capacity might not be attractive because the required derating might make it impossible for a boiler to meet peak load demands. Also, the modifications can only be made at a time when the unit is not needed to meet electrical demands.

Thus, large industrial boilers might be the most likely candidates for conversion to CWM. Again, fuel savings should be large enough to offset boiler modification costs. But peak capacity and possible derating should not be as great a concern for industrial boilers as for utility boilers.

Most experts agree that COM is not economically attractive for boilers smaller than 30 MW (100 x 10^6 Btu/hr).[15] However, CWM, with greater fuel savings than COM, might be economically attractive for smaller boilers, depending upon the amount of derating, boiler modifica- tions required, and environmental controls required.

As would be expected, the economics of conversion are more favorable for newer boilers than for older boilers. Generally, boilers have 40 year lives. A minimum of 10 to 20 years remaining useful life is generally required to make conversion to COM economically justifiable.[16] This figure may differ for CWM due to factors such as fuel savings, derating, and modifications/controls required.

The economics of conversion to CWM become less favorable as the capacity utilization factor for a boiler decreases. As boiler capacity factor decreases, fuel cost savings decrease, but the overall boiler conversion costs are unchanged. The results of a study of COM and CWM conversion economics indicate that, for a 31,780 kg steam/hr (70,000 lb/hr) oil-fired industrial boiler, the conversion costs exceed the fuel savings when the capacity factor drops below 20 percent.[17]

2.2.3 Boiler Geographical Location

Boiler location may play a significant role in determining the economic feasibility of converting to CWM combustion. It is unlikely that many boiler operators will maintain on-site facilities for the preparation of CWM. Instead, large centralized plants will receive, blend, and beneficiate the coals, then produce slurries with specific ash- and sulfur-content, heating value, and ash fusion temperatures. These slurries will then be transported by pipeline, barge, or tank car to the boiler site. Thus, the location of the boiler site in relation to these preparation facilities might determine the economics of conversion.

Figure 2.2-1 shows the geographical distribution of large domestic oil-fired industrial boilers (larger than 100 x 10^6 Btu/hr). This figure shows that over 80 percent of the boilers are located in EPA Regions 1-5, the Eastern and Midwestern states. These Eastern facilities will be more likely to convert to CWM than the Western facilities because many western states do not have adequate water supplies to support the production of CWM. Large centralized preparation plants will most likely be located in the eastern United States even though some western coal may be used in the slurry preparation.

2.3 REGULATORY REQUIREMENTS FOR CWM COMBUSTION

The conversion of existing oil-fired boilers to CWM will be subject to environmental regulations concerning air emissions and liquid and solid waste discharges. The discharge and disposal of liquid and solid wastes are governed by Federal and state regulations applicable to coal- fired boilers. Compared to oil-only firing, CWM combustion will result in increased levels

Region	No. of Combustors	Capacity In Megawatts
1	140	2,592
2	382	4,134
3	277	5,553
4	239	4,757
5	226	4,388
6	55	1,358
7	19	270
8	43	701
9	25	469
10	25	476
Total	1,431	24,698

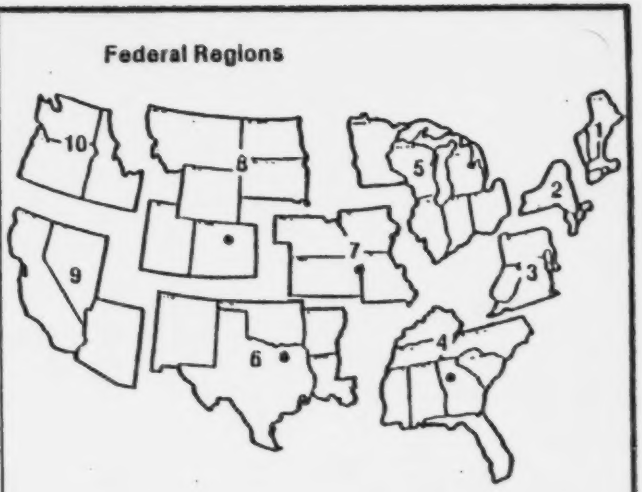

Figure 2.2-1. Regional distribution of oil-fired industrial boilers. [>30 MW (100 x 10^6 Btu/hr)][17]

of solid waste — waste from coal beneficiation, bottom ash, flyash, and possibly waste from flue gas desulfurization. These wastes are designated "non-hazardous" by EPA standards, and can be disposed of by well established methods. Liquid wastes are governed by effluent limitations guidelines established through National Pollution Discharge Elimination System (NPDES).

Conversion to CWM or the design of a new CWM-fired boiler could potentially be affected by three Clean Air Act (CAA) programs:

- new source performance standards (NSPS)
- prevention of significant deterioration (PSD), and
- nonattainment review.

These three programs are discussed in detail, with respect to COM conversions, in "Control of Criteria and Non-Criteria Pollutants From Coal-Oil Mixture Combustion," **EPA-600/7-83-040, NTIS PB 83-247247, August 1983.** This section summarizes the Clean Air Act programs as they pertain to CWM conversions.

In addition to the Federal programs discussed here, there may be state and local regulations which apply to CWM combustion.

2.3.1 New Source Performance Standards (NSPS)

Utility and industrial boilers with capacities greater than 73 MW (250 x 10^6 Btu/hr) are subject to separate NSPS promulgated in 1979 and 1971 (40 CFR 60, Subpart Da and 40 CFR, Subpart D, respectively). The 1979 NSPS, which in effect requires FGD and a fabric filter or an electrostatic precipitator on all new utility boilers, specifically exempts conversions of boilers originally designed to fire oil or gas to other fossil or non-fossil fuels (40 CFR 60 (40)(a)]. EPA's rulings concerning conversions of large (73 MW) industrial boilers not meeting the criteria of an electric utility have been varied but generally exempt industrial boiler conversions.[18]

No NSPS have been promulgated for industrial boilers with heat input capacities less than 73 MW (250×10^6 Btu/hr).

2.3.2 Prevention of Significant Deterioration (PSD)

The goal of the PSD program is to prevent deterioration of air quality which might result from unregulated new or modified sources of air pollutants. The PSD review process, which takes 12 to 24 months to complete, entails the following:

- control technology review,
- air quality review,
- air quality monitoring, and
- development of detailed source information.

Visibility impact analyses and growth impact analyses may also be included in some cases.

Boilers modified for CWM combustion are subject to PSD review if they meet both of the following criteria:

(1) the boiler is a major source of one or more criteria pollutant (PM, SO_2, NO_x, CO, hydrocarbons, or lead); and
(2) modification of the boiler results in a significant net emissions increase of any criteria pollutant from the source, as determined by de minimus levels set by EPA.[19]

A major source is defined as one which:

a) is in any one of 28 major source categories and has the "potential to emit" at least 100 tons per year of any criteria pollutant (PM, SO_2, NO_x, CO, hydrocarbons, or lead), or

b) is any other stationary source which has the "potential to emit" at least 250 tons per year of any criteria pollutant.

The "potential to emit" refers to the emissions from the source, at maximum design capacity, after application of any emission controls. A net emissions increase is significant if it exceeds the de minimus levels set by EPA. The de minimus levels for the pollutants of primary concern in CWM conversions are:

- PM: 25 tons/yr.
- SO_2: 40 tons/yr, and
- NO_x: 40 tons/yr.

All new large (73 MW) utility and industrial boilers firing CWM will be subject to PSD regulations. These boilers are classified among the 28 major source categories and have the "potential to emit" greater than 91 Mg (100 tons) per year of at least one pollutant-SO_2. SO_2 emissions of as low as 130 ng/J (0.3 lb/10^6 Btu) would result in annual emissions of about 318 Mg (350 tons), based on maximum design capacity of a 73 MW (250 x 10^6 Btu/hr) boiler. PM emissions of 40 ng/J (0.10 lb/10^6 Btu) result in annual emissions of 100 Mg/yr (110 tons/yr). And annual NO_x emissions of about 730 Mg (800 tons) result from an emissions rate of 300 ng/J (0.70 lb/10^6 Btu) in the same capacity boiler. Annual emissions would be greater for larger boilers.

Industrial boilers with heat input capacities of less than 73 MW (250 x 10^6 Btu/hr) are not listed in the 28 major source categories. However, many of these boilers have the potential to emit over 230 Mg/yr (250 tons/yr) of SO_2. Figure 2.3-1 shows annual SO_2 emissions, at maximum capacity, as a function of boiler size and fuel sulfur content. This figure indicates that for boilers larger than 14.7 MW (50 x 10^6 Btu/hr), SO_2 emissions must be less than 430 ng SO_2/J (1.0 lb SO_2/10^6 Btu) to meet the 230 Mg/yr (250 tons/yr) major source exemption criteria. For boilers larger

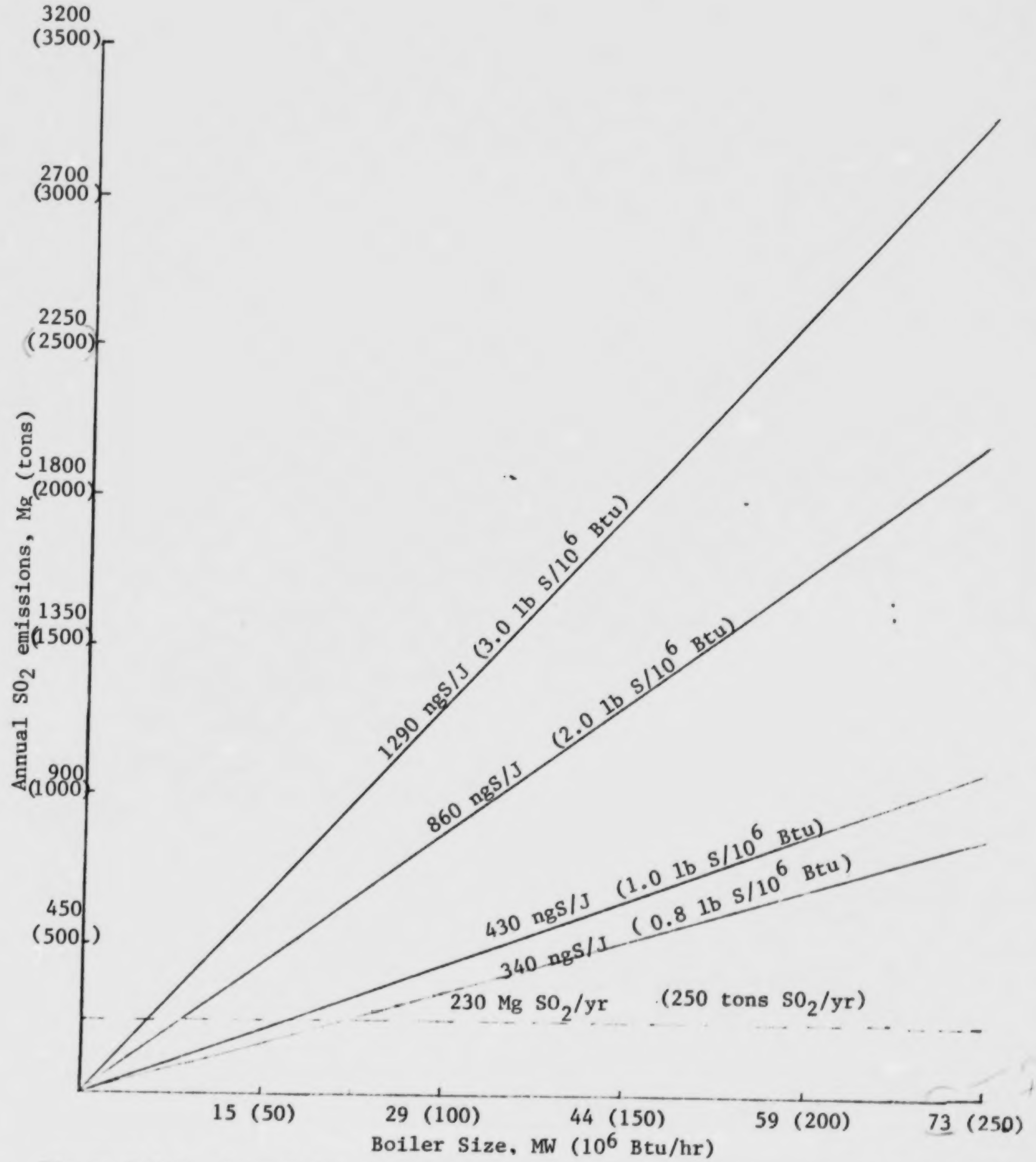

Figure 2.3-1. Annual SO_2 emissions as a function of boiler size and fuel sulfur content.

than 29.4 MW (100 x 10^6 Btu/hr), SO_2 emissions must be less than 260 ng SO_2/J (0.6 lb $SO_2/10^6$ Btu). Even if boiler emissions are below 230 Mg/yr (250 tons/yr), the plant at which the boiler is located may exceed this level. In such cases, the boiler may still be subject to PSD review.

Thus, most oil-fired boilers that are candidates for conversion to CWM are unlikely to be exempt from PSD review under the first exemption criterion. Therefore, the second criterion of net emissions increase must be evaluated carefully. As shown in the following calculations, the de minimus levels have been set low enough that emissions from CWM, excluding any intra-source reductions, essentially have to be no greater than oil-only levels to avoid PSD review. It should be noted that net emissions increases are calculated based on actual emissions before modification, so if the boiler fired very low sulfur distillate oil or natural gas it may be infeasible to reduce the net emissions increase below de minimus levels.[18]

The emissions from oil-only combustion before CWM conversion will depend in many cases on the state regulations applicable to existing oil-fired boilers. These regulations are specified in State Implementation Plans (SIPs). The current SIP's applicable to existing oil-fired units are shown in Table 2.3-1 for several states. The SO_2 regulations were obtained from an EPA summary (Reference 20). Particulate matter and NO_x regulations were obtained from the most recent SIP versions given in Reference 21.

Sources subject to PSD regulations must apply "Best Available Control Technology" (BACT), as determined by the regulatory agency having jurisdiction over the affected facility. In determining BACT, various control technologies must be evaluated on the basis of their environmental, energy, and economic impacts. The selected BACT must be at least as efficient as, and in some cases more efficient than, the technology which serves as the basis for any NSPS applicable to the source.

TABLE 2.3-1. SIP REGULATIONS FOR EXISTING OIL-FIRED BOILERS FOR CERTAIN STATES[a,b]

State	SO2	PM	NO_x
California	All sizes: Varies from 300 to 2000 ppm SO_2 depending on location; some locations: 0.5% S fuel limit.	10 lb/hr or .1 gr/scf generally; varies by location.	All sizes: 225 ppm (also varies by location
Florida[c]	250: "Reasonably available controls" 250: 1.1 lb/10^6 Btu, some counties; 2.75 lb/10^6 Btu other counties.	250: 0.1 lb/10^6 Btu 250: BACT	250: 0.3 lb/10^6 Btu 250: BACT
Illinois	All sizes: 1.0 lb/10^6 Btu 250: 0.8 lb/10^6 Btu (after 4/72).	All sizes: 0.1 lb/10^6 Btu	250: 0.3 lb/10^6 Btu 250: No regulation
Indiana	24: 6.0 lb/10^6 Btu 24 to 3081: 6 to 1.2 lb/10^6 Btu[f,g]	All sizes: 0.1 lb/10^6 Btu	No regulation
Kentucky	2.0 to 2.5 lb/10^6 Btu depending on size.[e] Also may vary with location.	Varies widely depending on boiler size, location.	No regulation
Maryland[d]	All sizes: 1 to 2% S fuel depending on location.	All sizes: $E = 1.026(I)^{-0.233}$ (before 1972). 25-250: $E = \log_{10}]6.597(I)^{-0.3}]$ (after 1972). 250: 0.1 lb/10^6 Btu (after 1972).	
Massachusetts	0.28 to 2.2 lb/10^6 Btu depending on location and size.[f]	All sizes: 0.12 to 0.15 lb/10^6 Btu.	

TABLE 2.3-1. (Continued) SIP REGULATIONS FOR EXISTING OIL-FIRED BOILERS FOR CERTAIN STATES[a,b]

State	S02	PM	NO_x
New Jersey	0.3% S fuel (May be higher in some locations.	250: 0.25 to 0.15 $lb/10^6$ Btu[f] 250: 0.1 $lb/10^6$ Btu	No regulation
New York	0.3 to 2.0% S fuel depending on location.[f]	250: 0.2 $lb/10^6$ Btu 250: 0.2 $lb/10^6$ Btu	250: 0.3 $lb/10^6$ Btu 250: No regulation
Pennsylvania	0.3 to 3 $lb/10^6$ Btu depending on location and size.	50: 0.4 to 0.1 $lb/10^6$ Btu 600: 0.1 $lb/10^6$ Btu	No regulation No regulation

[a] S02 regulations from Reference 20; PM and NO_x from Reference 21.

[b] Boiler sizes listed in 10^6 Btu/hr; Emission limits listed in $lb/10^6$ Btu.

[c] BACT: "Best Available Control Technology"; S02 standard applies to entire plant, not just one source.

[d] PM regs: vary by year of construction

E = $lb/10^6$ Btu allowable emissions
I = boiler heat input capacity, 10^6 Btu/hr

[e] Emission limit decreases as boiler size increases.

[f] Applies to entire plant.

[g] Sources also subject to air quality regulation.

2.3.3 Nonattainment Review

The 1977 Amendments to the Clean Air Act established a regulatory plan for certain areas of the country that are not in compliance with the National Ambient Air Quality Standards (NAAQS) for criteria air pollutants. In these designated nonattainment areas, there are precon- struction review requirements beyond the PSD requirements described above. In effect, offsetting emissions reductions, equivalent to the increase in emissions from the regulated source, must be obtained. These offset requirements apply to each pollutant for which the area is designated to have a nonattainment (NA) status. Emissions offsets are generally achieved by installing improved controls on existing sources in the vicinity of the affected source.

Since PSD and NA regulations apply to the entire plant where the boiler being converted to CWM is located, reductions in emissions within the plant can be credited against the emissions increase in switching from oil to CWM. However, the decision, for example, to reduce SO_2 emissions by burning lower sulfur fuel in another boiler will depend primarily on fuel prices and availability and boiler capacity factors. Any evaluation of the most technically and economically desirable scheme for CWM conversion at multiboiler plants would have to be on a site- specific basis.

2.4 ECONOMICS OF CWM COMBUSTION

Although the technical feasibility of CWM combustion appears certain, the economic viability must still be determined. Factors which are important in this determination include:

- capital availability,
- difference between oil (or gas) and coal prices and the relative escalation rates predicted,
- long-term fuel supply strategy/flexibility,

- availability and price of CWM,
- boiler modifications required,
- boiler size, age, and geographical location, and
- emission controls required.

Of these factors, the difference between oil and coal prices plays the major role in dictating the economic feasibility of converting to CWM. The fuel cost savings must be large enough to assure that annualized cost savings are realized. The higher the capital expenditures for modifications/emissions controls and the greater the required return on investment, the less likely that the economics of conversion will be favorable.

The relative rates of coal and oil/gas price escalation, as well as the security of supply, also impact the economic feasibility of CWM combustion. However, both are difficult to predict. The long-term fuel supply strategy must also be examined as well as the flexibility of burning substitute fuels if one supply should fail. Boilers converted to CWM will most likely be capable of burning oil and COM also.

The economics of CWM combustion are also affected by CWM availability and price. The cost of CWM is dependent upon the raw coal type, the cost of cleaning, and the cost of preparation. And with several CWM preparation facilities proposed or already under construction, the availability of CWM looks promising. The operators of these CWM preparation facilities will conceivably rely on coal supplies from several sources. In such a scheme, CWM preparation would not be halted if the supply from one region is discontinued due to miners' strikes, etc. The converted boiler facility will likely have the flexibility to burn COM or oil and may have back-up oil storage in place if the CWM supply should be discontinued.

As mentioned in Section 2.2, boiler size, age, capacity factor, and geographical location all directly impact the feasibility of conversion to CWM. The cost of boiler modifications will be very important in determining the economic feasibility of conversion.

The cost of pre-combustion, combustion modification, and post-combustion controls installed to meet environmental regulations may also have a significant impact on the economics of conversion. Applicable regulatory requirements were discussed in Section 2.3, and the cost of alternative emission control options to meet these regulatory requirements are presented in Chapter 5.

2.5 COAL-ALCOHOL MIXTURES

Coal-alcohol mixtures are another fuel alternative which could potentially replace oil or natural gas in existing boilers. But coal-alcohol mixtures are not as economically attractive as COM or CWM due to the high price of methanol. Thus, at this time, there is limited activity in the development of coal-alcohol mixtures as fuels. One firm in the United States, however, is devoted to the development of coal-alcohol mixtures and holds several patents in this area.[22]

Coal-alcohol mixtures consist of 50 to 75 percent pulverized cleaned coal slurried in alcohol. Methanol is typically used but ethanol, propanol, and butanol are also potential liquids for slurrying coal. The fuel-grade methanol, produced from coal or natural gas, would not be as pure as chemical-grade methanol. Fuel-grade methanol contains 5 to 10 percent water and higher alcohols, and has a heating value of about 20,970 kJ/kg (9000 Btu/lb).[23] The heating value of coal-alcohol fuels containing 70 percent coal could range from 22,100 kJ/kg (9500 Btu/lb) to 29,100 kJ/kg (12,500 Btu/lb). For comparison, heating values of CWMs containing 70 percent coal range from 16,300 to 23,250 kJ/kg (7000 to 10,000 Btu/lb).

Rheology tests of coal-methanol slurries conducted at the Colorado School of Mines indicate that at room temperatures the viscosities of coal-methanol slurries were about the same as coal-water slurries.[24]

It is expected that many of the same boiler modifications required for conversion to COM and CWM will be required to convert to CWM. But coal-alcohol mixtures must be transported and stored in vessels designed for highly flammable fuels such as natural gas and gasoline.

Very little coal-alcohol combustion or emission data are currently available. All available data is presented in Chapter 3 but further discussion of coal-alcohol mixtures will not be included in this report.

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CHAPTER 3

CWM EMISSIONS AND CONTROL OPTIONS

This chapter discusses the nature and magnitude of uncontrolled air emissions from CWM combustion and the technologies available to control these emissions. In most cases where an existing oil-fired boiler is to be converted to CWM combustion, the uncontrolled emissions of particulate matter (PM), and nitrogen oxides (NO_x) will be greater for CWM-firing than for oil-firing. The increased air emissions result from the contribution of coal ash and nitrogen to the combustion emissions. Emissions of SO_2 from CWM combustion may be less than or greater than oil-only SO_2 emissions, depending on the relative sulfur contents of the CWM and the oil. Trace element emissions from CWM combustion may be greater or less than those from oil-firing, depending upon the degree of beneficiation of the coal used in preparing the CWM. Nickel and vanadium emissions from CWM-firing should always be less than for oil-firing, however.

Sections 3.1 through 3.4 of this chapter summarize the available PM, SO_2, NO_x, and trace element emission test data for CWM combustion. Section 3.5 discusses organic emissions from CWM combustion.

At present, there are little data available on emissions from CWM combustion. In the absence of data for CWM-firing, the discussion focuses on data from coal- and COM-firing, with corollaries to CWM combustion.

Section 3.6 provides a brief review of the emission control technologies applicable to CWM-fired boilers. Basically, the applicable technologies are those currently in use on existing oil- and coal-fired boilers. Some newer technologies, still in the developmental or demonstration stage, may also be applicable to CWM units. Based on certain general criteria, such as the status of development, demonstrated effectiveness, use on existing oil- or coal-fired boilers, retrofit suitability, and multi-pollutant control capability, several technologies are selected for further evaluation of their environmental, and cost impacts for CWM- fired boilers. (Those impacts are presented in subsequent chapters of this report.)

3.1 PARTICULATE MATTER (PM) EMISSIONS

Measured emissions of PM (fly ash) from boilers firing CWM are a function of the ash content of the CWM and the amount of ash deposition in the boiler. Since the ash content of residual oil is negligible when compared to the ash content of coal, PM emissions from CWM combustion will far exceed those from oil combustion. Although there are no data available which indicate the distribution between fly ash and bottom ash for CWM combustion, the distribution should be similar to that of coal combustion.[1]

Pulverized coal units produce 60 to 85 percent fly ash and the remainder bottom ash.[2] Data for COM combustion indicate that about 80 percent of the total COM ash is emitted as fly ash. Recent data collected for small test boilers (100 hp and 700 hp) firing CWMs with 60 percent coal suggest that from 75 to 95 percent of the ash leaves the boiler as fly ash.[3] But these values were determined under poor combustion conditions and may not be indicative of the fly ash - bottom ash split for a full-size boiler operating efficiently.

CWMs contain approximately 1 percent additives and stabilizers. In the early development of CWMs, these additives were sodium-based and chloride-based compounds that had severe adverse effects on the boiler. Other additives, such as ammonium-based compounds are now being substituted. Although these compounds could potentially increase PM emissions, their impact should be minimal.

3.1.1 Mass Emissions and Opacity

Potential PM emissions in ng/J (lb/10^6 Btu) for CWMs having various ash contents and heating values are shown in Figure 3.1-1. These values assume that 80 percent of the ash contained in the CWM is emitted as fly ash and 20 percent is removed as bottom ash. These values are also based on CWMs containing 70 percent coal and 30 percent water. Figure 3.1-1 indicates that PM emissions range from about 344 ng/J (0.8 lb/10^6 Btu) for a 1 percent ash CWM to 3010 ng/J (7.0 lb/10^6 Btu) for a 6 percent ash CWM. On an annual basis, the difference between firing a CWM with 1 percent ash and one with 6 percent ash is significant. For example, this difference is greater than 5900 Mg (6500 tons) of PM annually for a 73 MW (250 x 10^6 Btu/hr) heat input boiler operating at 100 percent capacity.

One series of CWM emission tests reported in the literature used CWMs with ash contents of about 7.0 percent and heating values of 18,100 to 18,600 kJ/kg (7800 to 8000 Btu/lb). The resulting PM emissions, due to the ash in the coal, ranged from 1380 to 3700 ng/J (3.2 to 8.6 lb/10^6 Btu).[3] But due to the poor combustion conditions, large quantities of unburned carbon also exitted the boiler as PM, bringing total PM emissions to 6750 to 8640 ng/J (15.7 to 20.1 lb/10^6 Btu).
Table 3.1-1 presents the data given in Reference 3.

Another series of CWM tests reported in the literature used a CWM with 3 percent ash and a heating value of 21,200 kJ/kg (9100 Btu/lb). Although no PM emissions testing was conducted in this series, the emissions can be estimated. Assuming that 80 percent of the ash leaves the boiler as fly ash, PM emissions would range from 1120 to 1160 ng/J (2.6 to 2.7 lb/10^6 Btu). This approximation of PM emissions illustrates the effect of CWM ash content and heating value on PM emissions.

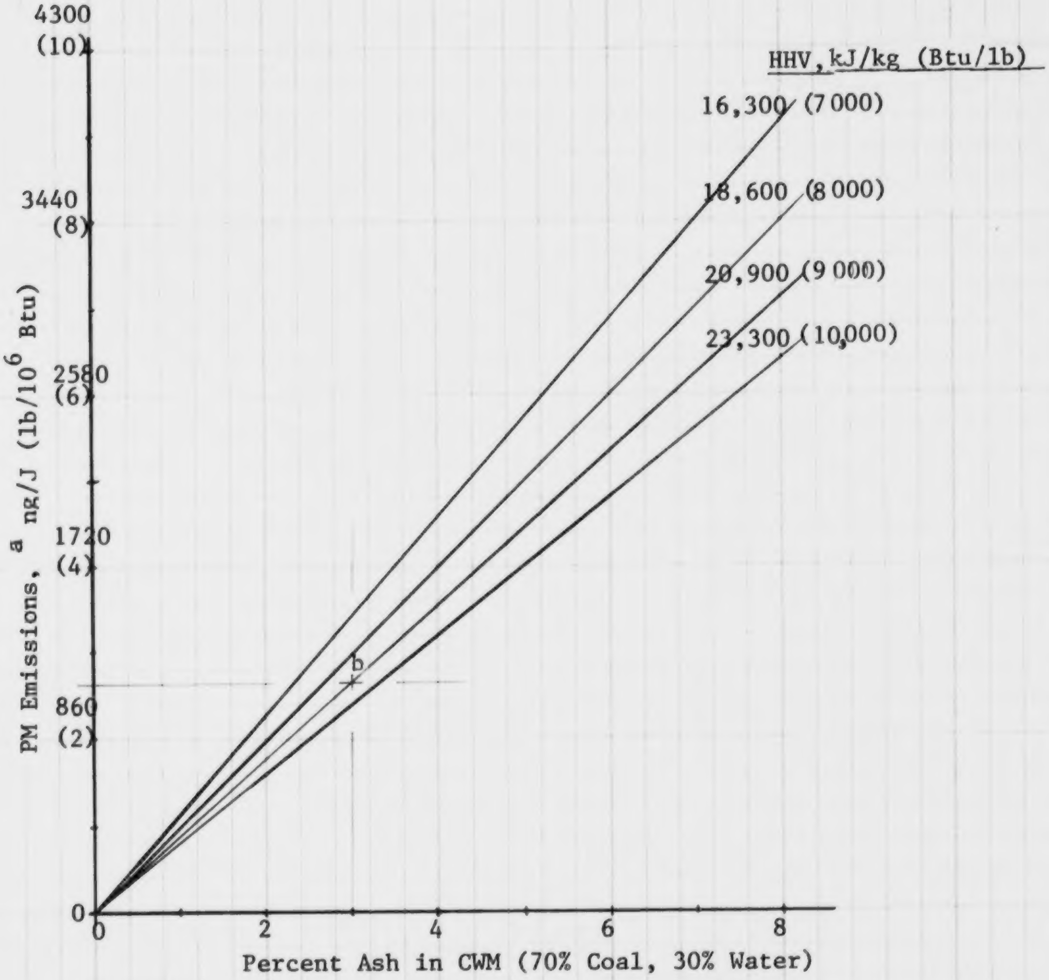

Figure 3.1-1. Potential PM emissions from CWM-firing.

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[a] PM emitted based on 80/20 distribution between fly ash and bottom ash.

[b] Ash content and heating value of CWM tested at Alliance, Ohio.

TABLE 3.1-1. PM EMISSIONS FROM COAL-WATER MIXTURE COMBUSTION[a]

Coal-Water Mixture	1[b]	2[b]	3[b]	4[b]	5[c]	6[c]	7[d]
Weight Percent Coal	60.0	61.0	60.0	60.0	61.3	59.8	60.6
Weight Percent Ash	7.0	7.1	7.0	7.0	7.2	7.0	6.7
Heating Value kJ/kg (BTU/lb)	18,200 (7810)	18,500 (7940)	18,200 (7810)	18,200 (7810)	18,600 (7980)	18,100 (7780)	18,400 (7898)
Carbon Conversion Efficiency %	85.2	83.9	83.7	81.2	89.7	87.9	94.1
Total PM, ng/J (lb/10^6 Btu)	6740 (15.67)	7000 (16.32)	6970 (16.62)	8650 (20.12)	4180 (9.71)	4960 (11.53)	2730 (6.35)
PM due to ash in CWM, ng/J (lb/10^6Btu)	2880 (6.7)	2880 (6.7)	2880 (6.7)	3700 (8.6)	1590 (3.7)	1980 (4.6)	1380 (3.2)

[a] Data presented in Reference 3.

[b] 100 hp boiler, full load test.

[c] 100 hp boiler, half load test.

[d] 700 hp boiler, 3/4 load test.

One series of coal-alcohol combustion tests was also reported in the literature.[3] These tests were performed using a 100 hp boiler at full-load. Table 3.1-2 presents the compositions of the various coal- alcohol mixtures tested and the resulting PM emissions. The PM emissions ranged from 1500 to 6190 ng/J (3.5 to 14.4 lb/10^6 Btu) depending upon the composition of the coal-alcohol mixtures. Again, a significant portion of this PM is a result of unburned carbon. PM emissions based on "ash only" ranges from 990 to 3100 ng/J (2.3 to 7.2 lb/10^6 Btu).

No opacity data are available for CWM combustion. However, since opacity has been roughly related to mass emissions (PM concentrations) for any given boiler, it is expected that CWMs with low ash content should result in lower opacity as compared to CWMs with high ash content. COM combustion test data indicated opacities ranging from 2 to 35 percent, with the higher opacities associated with increased COM ash levels.[4] Opacities for CWM combustion should follow the same trend.

3.1.2 Fly Ash Particle Size Distribution

There are currently no data available on CWM fly ash particle size distribution. As with COM combustion, particles emitted from CWM combustion tend to agglomerate. That is, many fly ash particles leaving the boiler cluster together to form single particles which are larger than the coal particles in the CWM being burned.

The combustion of CWMs is expected to be similar to that of a moist coal. Thus, fly ash from CWM-firing may be similar to fly ash from pulverized coal-firing. Table 3.1-3 presents typical physical properties of fly ash from pulverized coal-fired boilers. The fly ash particle size ranges from 0.5 to 100 micrometers with 60 to 90 percent of the particles less than 44 micrometers.

TABLE 3.1-2. PM EMISSIONS FROM COAL-ALCOHOL MIXTURE COMBUSTION[a,b]

Coal-Alcohol Mixture	1	2	3	4	5	6
Weight Percent Coal	60	61.0	59.8	55.9	54.9	56.0
Weight Percent Methanol	40	39.0	31.5	26.0	17.8	8.7
Weight Percent Water	-	-	8.7	18.1	27.3	35.3
Weight Percent Ash	6.5	6.7	8.0	7.5	7.3	7.5
Heating Value, kJ/kg (Btu/lb)	27,100 (11,618)	27,100 (11,649)	24,900 (10,673)	22,500 (9,639)	20,300 (8,710)	18,500 (7,960)
Carbon Conversion Efficiency %	97.4	92.2	86.9	95.9	90.2	88.8
Total PM Emissions ng/J (lb/10^6 BTU)	1510 (3.52)	3410 (7.94)	5710 (13.27)	6200 (14.41)	5510 (12.82)	5440 (12.64)
PM Emissions due to Ash in Fuel ng/J (lb/10^6 Btu)	990 (2.3)	1810 (4.2)	2750 (6.4)	2880 (6.7)	3100 (7.2)	2970 (6.9)

[a] Data presented in Reference 3.

[b] 100 hp boiler, full load test.

TABLE 3.1-3. TYPICAL PHYSICAL PROPERTIES OF FLY ASH FROM PULVERIZED COAL-FIRED PLANTS

Constituent	Range
pH	6.5 to 4.5
Particle size range, m	0.5 to 100
Average percent of particles passing 325-mesh sieve, (44 m), %	60 to 90
Bulk density (compacted), kg/m^3	1,100 to 1,300
Specific gravity	2.1 to 2.6
Specific area per gram, cm^2/g	3,300 to 6,400

Source: Reference 5.

3.2 SULFUR DIOXIDE (SO_2) EMISSIONS

The SO_2 emissions from CWM combustion are a direct function of the fuel sulfur content. The CWM sulfur content is in turn determined by the sulfur content of the coal used in the CWM. If a CWM contains 70 weight percent coal, its sulfur content will be 70 percent that of the coal. At least 95 percent of the fuel sulfur is typically emitted as SO_2. (CWMs made with coal that has highly alkaline ash may emit slightly less than 95 percent of the fuel sulfur since the alkaline ash serves to retain some of the fuel sulfur.)

For a given CWM the SO_2 emissions, based on 100 percent of the fuel sulfur emitted as SO_2, can be calculated with the following equation:*

$$SO_2 = \left(\frac{x\ \text{lb S}}{100\ \text{lb CWM}}\right)\left(\frac{1\ \text{lb-mole S}}{32\ \text{lb S}}\right)\left(\frac{1}{1}\ \frac{\text{lb-mole } SO_2}{\text{lb-mole S}}\right)\left(\frac{64\ \text{lb } SO_2}{\text{lb-mole } SO_2}\right)\left(\frac{\text{lb CWM}}{y\ \text{Btu}}\right)$$

$$SO_2 = 0.02\ x/y \qquad (3\text{-}1)$$

where SO_2 = lb SO_2/Btu [x 10^6 = lb $SO_2/10^6$ Btu]
x = Sulfur in COM, %
y = CWM heating value, Btu/lb

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*To convert lb/10^6 Btu to ng/J, multiply by 430.

SO_2 emissions from CWMs prepared with beneficiated coal are substantially lower than SO_2 emissions from CWMs prepared using run-of-mine (ROM) coal. And essentially all CWMs will be prepared with highly beneficiated coal. Beneficiation is effected using physical coal cleaning techniques to remove ash, pyritic sulfur, and other mineral matter present. Coal contains two major types of sulfur — inorganic (pyritic sulfur) and organic.

Pyritic sulfur is present in discrete particles which are liberated from the coal when the coal is crushed. Pyritic sulfur (s.g. = 4.5) is denser than coal (s.g. = 1.30-1.40) and is insoluble in water. Thus, pyritic sulfur can be removed by physical cleaning methods used to remove other heavy mineral matter. Advanced physical coal cleaning techniques are capable of removing up to 90 percent of the pyritic sulfur in coals.[6]

Organic sulfur, on the other hand, is chemically bonded to the organic carbon of coal and can only be removed by breaking the chemical bonds. Thus, the amount of organic sulfur present defines the lowest limit to which a coal may be cleaned with respect to sulfur removal by physical methods.[6] The organic sulfur content of coals ranges from 30 to 70 percent of the total sulfur content.

CWMs typically contain about 1 percent additives and stabilizers. These additives and stabilizers are often alkaline compounds which react with SO_2, forming sulfate and sulfite salts. Although these alkaline compounds may reduce SO_2 emissions very slightly, they can have an adverse effect on boiler operation and PM emissions. For this reason, many CWM developers are examining alternate additives and stabilizers, such as ammonium-based compounds.

3.3 NITROGEN OXIDE (NO_X) EMISSIONS

Emissions of NO_x from boilers firing CWM are more difficult to quantify for the various applications than are PM and SO_2 emissions. Emissions of NO_x can vary not only from boiler to boiler, but also with differences in CWM nitrogen content, excess air, and even boiler load. The water content of the CWM will also play a role in the levels of NO_x emitted.

Limited test data, however, are available regarding CWM combustion. Therefore, to characterize NO_x emissions expected for CWM combustion, an examination of the fundamentals of NO_x formation is made. The discussion presents the factors affecting the production of NO_x emissions. Available test results indicate that the emissions from CWM combustion should follow the same general trends as those noted for the parent coal. Thus, to relate how these factors may be projected to CWM combustion, the effects of these factors on the combustion of coal, oil, and coal- oil mixtures are presented.

3.3.1 NO_x Formation

Emissions of NO_x from combustion processes are due to two types of nitrogen oxidation. Thermal NO_x refers to those oxides resulting from the thermal fixation of nitrogen contained in the combustion air. Fuel NO_x (or organic NO_x) refers to the oxides formed by conversion of chemically- bound nitrogen in the fuel. The relative contributions of both types of NO_x emissions to total NO_x emissions depend upon the fuel type (coal, oil, COM, CWM) and composition and operating conditions for combustion.

For conventional combustion equipment the kinetic mechanism for thermal NO_x formation is generally coupled to the mechanism for the oxidation of the fuel's hydrocarbon constituents. For instance, both mechanisms are affected by physical aspects of the combustion system such as mixing in the flame zone. Zeldovich proposed what is now the most widely accepted mechanism for the production of thermal NO_x:

$$N_2 + O \qquad NO + N$$

$$N + O_2 \qquad NO + O$$

$$N + OH \qquad NO + H$$

The first reaction is thought to be the rate-determining reaction since it has the largest activation energy (317 kJ/mol).[7]

Thermal NO_x formation has been described by the following:

$$[NO] = k_1 e^{(-k_2/T)} [N_2][O_2]^{\frac{1}{2}} t$$

where: [ ] = mol fraction of the indicated specie
T = absolute temperature
t = residence time
k_1, k_2 = constants determined from experimental data.

Examining this equation, the amount of NO formed is noted to depend upon the combustion temperature, the concentrations of the reactants, and the residence time in the flame zone. Data gathered on the combustion of various fuels verify the impact of these factors on total NO_x production. Temperature has been found experimentally to have the greatest influence on thermal NO_x formation. In fact, below about 1760°C (3200°F), thermal NO_x is not the major contributor to total NO_x emissions.[8]

Some studies conducted under controlled conditions indicate that fuel NO_x may account for up to 80 percent of the total NO_x emitted from coal combustion. And as seen in Table 3.3-1, this fuel NO_x results from the oxidation of from 5 to 60 percent of the nitrogen contained in the fuel.

TABLE 3.3-1. CONTRIBUTION OF FUEL NO_X TO TOTAL NO_X FOR OIL AND COAL

Fuel	Fuel Nitrogen Converted to NO_x, %	Fuel NOx Contribution to Total NO_x, %
Oil	20-90	up to 80[a]
Coal	5-60	up to 80

[a] For residual oil.

Source: Reference 7, 9, 10.

Fuel NO_x formation can be viewed as oxidation of volatilized nitrogen and oxidation of char nitrogen. Char nitrogen is oxidized at a much slower rate than volatilized nitrogen; thus, most of fuel NO_x emissions are due to volatilized nitrogen oxidation. One source suggests that between 60 and 80 percent of fuel NO_x is from volatilized nitrogen.[17]

Fuel NO_x formation is strongly dependent upon the fuel/air ratio, decreasing as fuel/air ratio increases in the vicinity where volatilization occurs. This ratio primarily affects the oxidation of volatilized nitrogen, with char nitrogen oxidation being insensitive to the ratio. Fuel NO_x formation is relatively insensitive to changes in combustion zone temperature. Char nitrogen oxidation is only a weak function of temperature. Although the amount of volatilized nitrogen increases with increasing temperature, the degree of conversion of volatilized nitrogen to NO_x decreases with increasing temperature. Thus, the overall NO_x formation remains relatively stable with increasing temperature.

3.3.2 Excess Combustion Air

Data from CWM combustion tests are insufficient to draw conclusions about the effect of excess air on total NO_x emissions. But, referring back to the reaction rate equation, theory indicates that NO_x should increase as excess air (oxygen and nitrogen) increases. Indeed, as can be seen in Figure 3.3-1, this trend is well noted for the combustion of COMs. And by examining Figure 3.3-1, total NO_x (as indicated by NO concentration) increases not only with increasing excess air, but also with increasing fuel nitrogen content. As evidenced by the relatively constant distance between the excess air lines in Figure 3.3-1, there appears to be a constant effect on NO_x concentration exerted by the excess air level for COMs that contain 50 percent or more coal.[4]

3.3.3 Slurry Composition and Fuel Nitrogen Content

From the previous discussion of NO_x formation, flame temperature was noted to be the single most important factor governing thermal NO_x formation. The water constituent of the CWM has a tendency to reduce the combustion temperature from that of the parent coal by acting as a heat-sink for the heat of combustion. Even though the water in a 70 percent slurry reduces the combustion efficiency by only about 3 percent, the adiabatic flame temperature is expected to be reduced by about 149°C (300°F). Indeed, this appears to be the case based on the results of the limited CWM combustion tests. Flame temperatures during CWM firing were 93 to 204°C (200 to 400°F) lower than temperatures when the parent coal was fired. Corresponding reductions in the NO_x emissions measured for CWM were noted for these tests as well. The lower flame temperature for CWM firing would

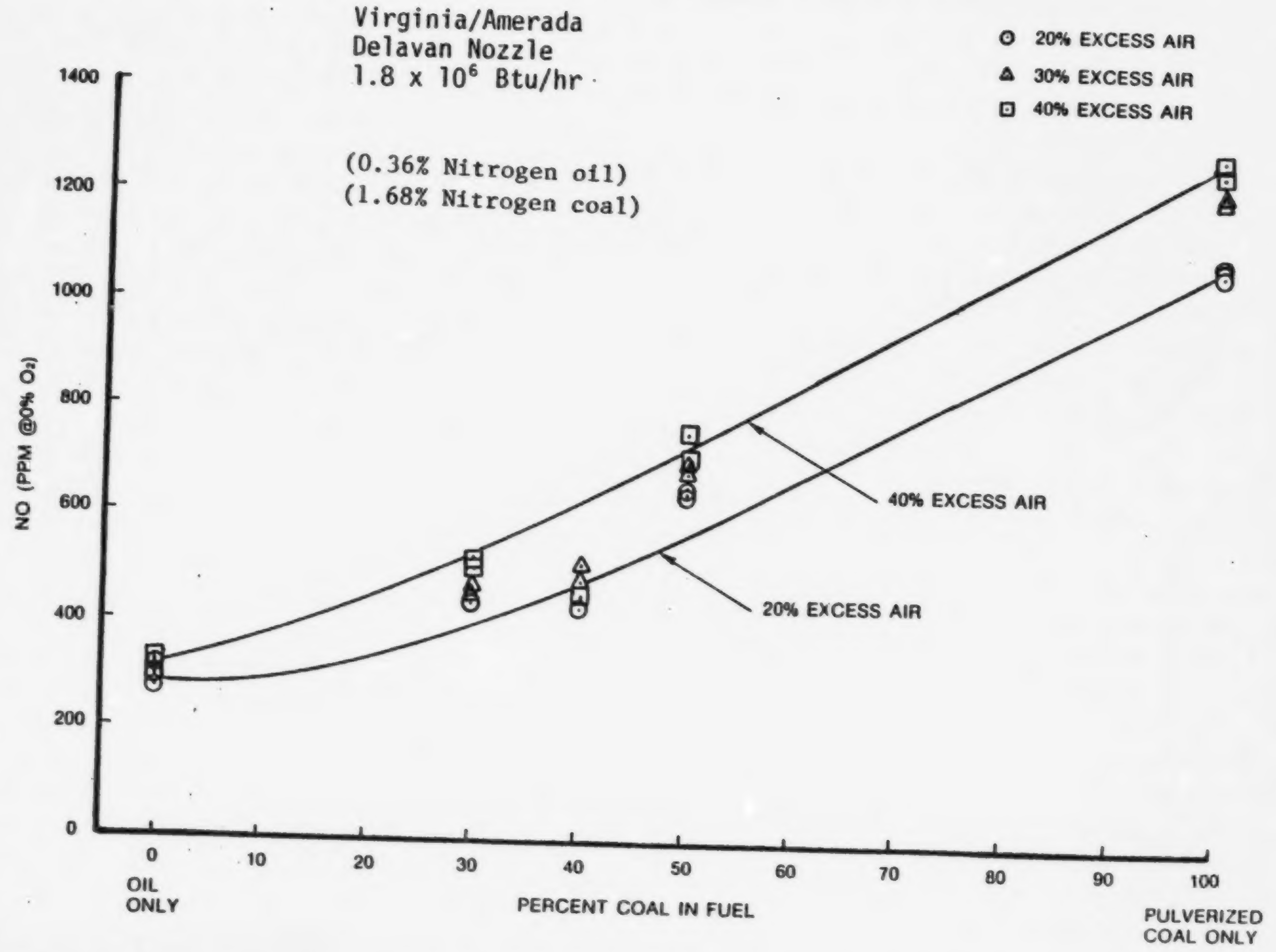

Figure 3.3-1. No_x emissions from COM combustion in laboratory-scale furnace 0.5 MW (1.8×10^6 Btu/hr).[11]

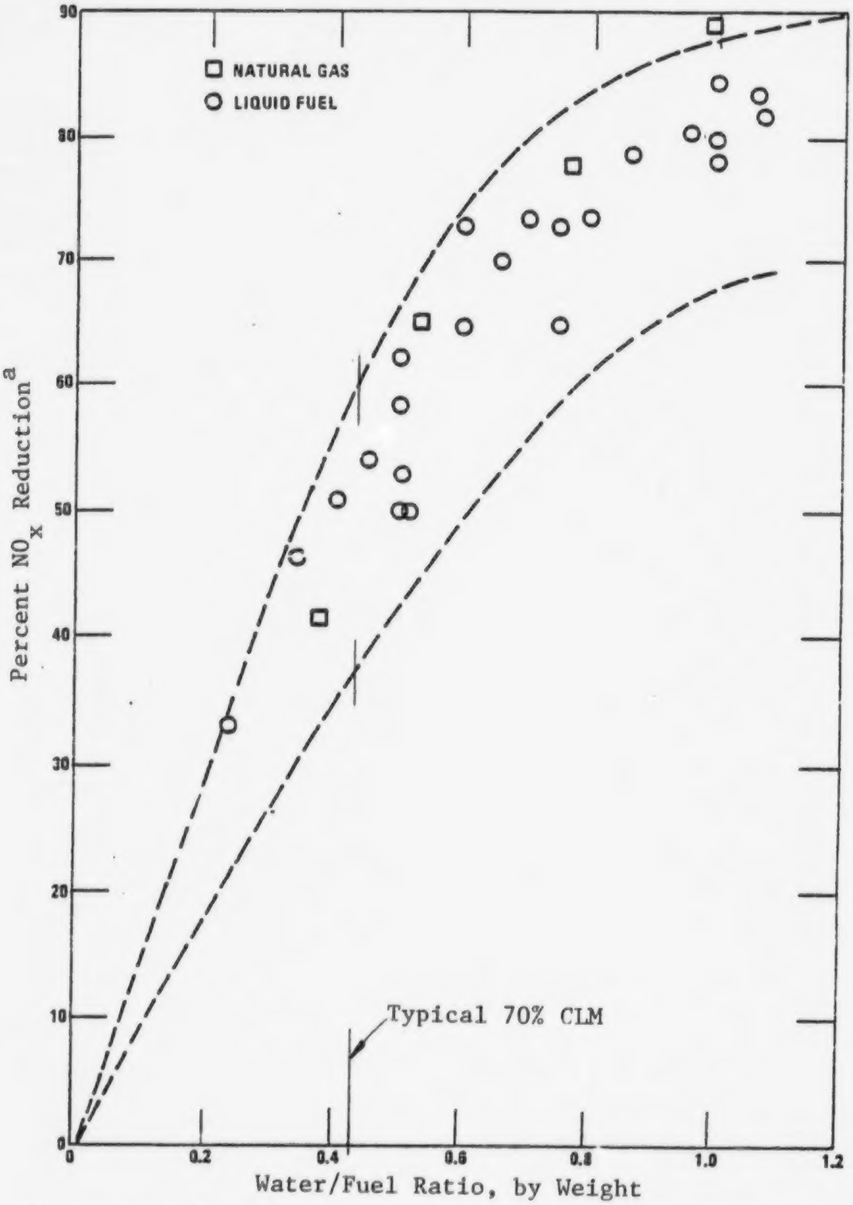

Figure 3.3-2. Effectiveness of water/steam injection in reducing NO_x emissions from gas turbines.[12]

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[a] Dashed lines are computed reductions based on maximum and minimum efficiencies.

be expected to produce lower thermal NO_x production, in the absence of other effects.[1]

The decrease in NO_x formation with water addition is expected. The new source standards for NO_x emissions from stationary gas turbines is based on the addition of water as a means of reducing NO_x emissions. Figure 3.3-2 indicates the effectiveness of water injection in reducing NO_x formation for natural gas and liquid fuels combusted in gas turbines. The dashed lines in the figure indicate the calculated bounds of the NO_x reduction achievable by water injection.

NO_x emissions for CWM firing were seen to be less than the coal- only firing of the same coal used in preparing the CWM. NO_x emission data gathered during some recent CWM testing are presented in Figure 3.3-3. NO_x emissions from CWM-firing were 40 and 54 percent lower than those from the parent coal.

A second indication from the CWM test results was that CWM burns like a moist coal when burning is stabilized. Therefore, emissions are expected to be affected in much the same manner as emissions from moist coal firing.[1] NO_x emissions from the combustion of high moisture content lignite also are lower than coal only emissions, primarily due to lower flame temperatures.

As the flame temperature is reduced and thermal NO_x production becomes less of a factor in total NO_x formation, the effect of fuel nitrogen content on NO_x formation becomes important. In Figure 3.3-1, these effects are noted for COMs of varying compositions (and therefore varying nitrogen contents). As the fuel nitrogen content is increased from 0.36 percent for oil to 1.68 percent for coal, NO_x emissions increase from about 300 ppm NO to about 1100 ppm NO for 20 percent excess air.[11] Therefore, although NO_x emissions will be lower due to the moisture content, the emissions are still proportional to the nitrogen in fuel.

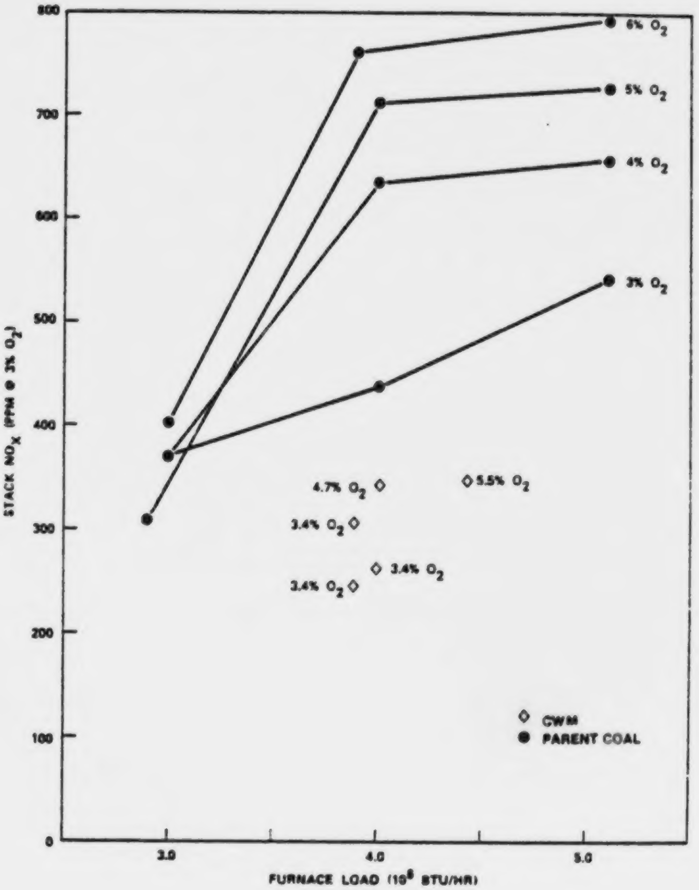

Figure 3.3-3. NO_x emissions from CWM combustion tests.[1]

Unlike COM whose composition can be varied, within limits, to achieve desired levels of sulfur or nitrogen, CWM formulations will be based on the optimum concentration that can be effectively handled and burned with a stable flame. Therefore, fuel nitrogen content of CWM will be solely dependent upon the nitrogen content of the parent coal.

3.3.4 Burner Design

Burner design can effectively reduce NO_x formation by impacting flame shape, size, and temperature. Two burner designs were examined in a study of emissions from COM combustion. One design resulted in a longer, more diffuse flame than the other burner and generally demonstrated lower fuel NO_x formation and lower overall NO_x emissions than the emissions from the other burner.[13]

In general, fuel NO_x increases with increasing fuel nitrogen content. Increases in fuel NO_x formation also result from the turbulent mixing of oxygen with volatile constituents of the nitrogen in the fuel. The testing reported for CWM was conducted using a burner that introduced a high degree of swirl in order to maintain stable combustion. Although NO_x formation would be expected to increase due to the swirl, the NO_x formation rate did not increase dramatically. The decrease in flame temperature for CWM firing apparently had a greater effect on overall NO_x formation, countering the effects of increased mixing.

3.3.5 NO_x Data

NO_x emissions from CWM firing are compared to NO_x emissions from the parent coal in Figure 3.3-3. The CWM tested contained 1.03 percent nitrogen and was made from the clean parent coal (1.61 percent nitrogen) that was also tested. In all cases the NO_x emissions from CWM firing were lower than the normal pulverized coal firing of the parent coal. Although the data are limited and additional study is needed to draw concrete conclusions, it appears that the lower flame temperatures associated with CWM combustion are the primary reason for lower NO_x emissions.[1]

Additional NO_x data for CWM and coal-alcohol combustion tests may be found in Reference 3. However, this data may not be representative of NO_x emissions due to the oxygen-starved conditions of the tests.

3.4 TRACE ELEMENT EMISSIONS

Trace elements in the CWM fuel exit the boiler either with the bottom ash or with the flue gas, provided there is not significant ash deposition in the boiler. Most of the trace elements emitted with the flue gas are associated with the fly ash, though some may remain in the vapor phase.

Two concepts, labeled partitioning and enrichment, are commonly used to characterize the behavior of trace elements in the combustion process. Partitioning refers to the distribution of trace elements among the various boiler outlet streams: bottom ash, fly ash, and flue gas. Enrichment, on the other hand, refers to the difference in trace element concentration in the bottom ash and fly ash as a function of particle size.

Based on their partitioning and enrichment behavior, trace elements can generally be divided into four classes:

Class 1: Elements which are approximately equally distributed between fly ash and bottom ash in proportion to weight difference between the two), or show little or no tendency to be enriched on small particles.

Class 2: Elements which tend to be associated more with the fly ash than the bottom ash or elements which show increasing enrichment with decreasing particle size.

Class 3: Elements which alternately exhibit both Class 1 and Class 2 behavior.

Class 4: Elements which are emitted in the gas phase.

This study is concerned with the emissions of the following trace elements from CWM combustion: arsenic (As), beryllium (Be), cadmium (Cd), chromium (Cr), nickel (Ni), selenium (Se), vanadium (V), and mercury (Hg). Table 3.4-1 shows the classification of these elements with respect to the four categories described above.

The amount of trace elements emitted from a particular boiler is dependent on:

- combustion temperature,
- fuel feed mechanism,
- characteristics of the flue gas, and
- CWM properties (trace element concentration).

The combustion temperature determines the extent to which specific trace elements are volatilized and thus the extent to which they may be emitted with the fly ash or flue gas. The fuel feed mechanism influences the partitioning of non-combustible trace elements between the bottom ash and fly ash. The temperature of the flue gas affects the relative amounts of volatile trace elements which are emitted condensed on the fly ash particles compared to being emitted as a vapor.

The concentration of trace elements in the coal and the percentage of coal used to prepare the CWM will determine the concentration of trace elements in the CWM. Table 3.4-2 shows average trace element concentrations for three coals and for a typical residual oil. These data show that, on the average, coal has higher concentrations of arsenic, beryllium, chromium,

TABLE 3.4-1. CLASSIFICATION OF TRACE ELEMENTS[a]

Trace Element	Classification[b]	Comments
Arsenic (As)	Class 2	-
Beryllium (Be)	Class 3	Has also exhibited Class 1 and Class 2 behavior in some studies.
Cadmium (Cd)	Class 2	-
Chromium (Cr)	Class 3	Has also shown Class 1 and Class 2 behavior in some studies.
Nickel (Ni)	Class 3	Has also shown Class 1 and Class 2 behavior.
Selenium (Se)	Class 2	Some selenium also emitted in gas phase (Class 4).
Vanadium (V)	Class 3	Has also shown Class 1 and Class 2 behavior.
Mercury (Hg)	Class 4	Class 4 at normal stack temperatures (149°C[300°F]); lower temperatures will cause condensation of gaseous mercury, resulting in Class 2 behavior.

[a] Reference 14.

[b] See text for explanation of Classes.

TABLE 3.4-2. AVERAGE TRACE ELEMENT CONCENTRATIONS IN COAL AND RESIDUAL OIL (ppm).

Trace Element	Eastern Bituminous	Western Bituminous	Bituminous	Residual Oil
Arsenic (As)	11.4	1.94	8.82	0.8
Beryllium (Be)	1.00	0.86	0.96	0.08
Cadmium (Cd)	0.42	1.28	0.66	2.27
Chromium (Cr)	31.2	11.8	25.9	1.3
Mercury (Hg)	0.21	0.099	0.18	0.04
Nickel (Ni)	19.1	14.8	17.9	42.2
Selenium (Se)	3.01	1.54	2.60	0.7
Vanadium (V)	37.2	23.7	33.5	160

mercury, and selenium. Residual oil has higher concentrations of cadmium, nickel and vanadium.

Combustion of CWM should result in reduced emissions of cadmium, nickel, and vanadium compared to combustion of oil. And, although run-of-mine (ROM) coal contains higher concentrations of other trace elements than oil does, a CWM prepared for combustion may actually contain lower quantities of trace elements than oil does. A significant amount, 30 to 60 percent, of trace elements are removed by physical coal cleaning techniques. The effect of physical coal cleaning on trace element removal is discussed in greater detail in Section 4.7.1.

3.5 POLYNUCLEAR ORGANIC MATERIAL (POM)

The amount of POMs emitted from any combustion source is dependent on the formation and the transformation mechanisms of the POM. POMs are formed in the combustion zone either by the breakdown of larger molecules or by the building up of smaller ones. Evidence is available to indicate that POMs form in the vapor phase and later condense on particulate matter in the flue gas.[23] POM formation is related to combustion efficiency and POM transformations are related to boiler and downstream flue gas temperatures. Oil-only combustion has been shown to contribute almost no POM emissions to the environment while coal-only combustion produces POM emissions in unpredictable patterns.[23]

A list of organic matter emitted during coal combustion is presented in Table 3.5-1. Nearly all of the organics presented in this table are POMs and many are known carcinogens. Uncontrolled emission data for POMs are limited. Table 3.5-2 presents data for controlled POM emissions. And it has been reported in the literature that effluent POM concentrations do not display significant changes on passage through particulate controls, including precipitators.[5]

TABLE 3.5-1. ORGANIC SPECIES DETECTED FROM COALFIRED POWER PLANTS

Specific Compounds Identified

Styrene
dichlorobenzene
C_2, C_3, C_4 substituted styrenes
azulene
substituted benzenes
naphthalene
methylnaphthalenes
1 1-diphenyl ethane
1, 1-diphenyl butane
phenanthrene/anthracene
methyl phenanthrenes
1,1-diphenyl ethylene
di-tolylethane
di-tolyethylenes
silicones
9, 10-dihydrophenanthrene
methyl stilbene
ditoyl stilbene
methyl phenanthrene
phenylnaphthalene

benzoic acid

Types of Organics Species Identified

general aromatic and aliphatic compounds
esters (probably mono-and di-substituted aromatics)
phthalates (beginning at dimethyl)
other carbonyls
long chain fatty acid esters
benzoates

Species Possibly Present

phenols
secondary or tertiary amides
aliphatic esters
aldehydes
ketones

TABLE 3.5-2. CONTROLLED POM EMISSION FACTORS[a]

POM	Detection limit, g/kg	Emission factor, g/kg
Dibenzothiophene	0.8	4
Anthracene/phenanthrene	0.8	159
Methylanthracenes/phenanthrenes	1.7	10
Dimethylanthracenes/phenanthrenes	0.8	3
Fluoranthene	0.8	164
Pyrene	0.8	–[b]
Methylfluoranthenes/pyrenes	0.8	19
Benzo(c)phenanthrene	0.8	5
Chrysene/benz(a)anthracene	0.8	617[c]
Dimethylbenz(a)anthracenes	5.0	29[c]
Benzofluoranthenes	0.8	329[c]
Benzopyrenes (and perylene)	0.8	–[b,c]
Methylcholanthrenes	5.0	85[c]
Indeno(1,2,3c,d)pyrene	0.8	3[c]
Dibenz(a,h)anthracene (or isomers)	0.8	13[c]
Dibenzo(c,g)carbazole	3.3	–[b,c]
Dibenzopyrenes	3.3	22[c]
Methylchrysenes (or isomers)	1.7	37
Anthanthrene/benzo(ghi)perylene	1.7	–[b]
Total POM		1,499
Total Carcinogenic POM		1,103

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[a] Average of duplicate analyses of two measurements.

[b] Not detected.

[c] These groups contain known carcinogens.

Source: Reference 5.

Because POM formation is a function of combustion efficiency, less efficient boilers are expected to emit relatively greater quantities of POMs than would utility boilers operated as high efficiencies. POM emissions from industrial boilers have been reported by one source to be an order of magnitude higher than those of utility boilers.[5] These results may not be representative, however. Another source indicates that POM emissions from industrial boilers are below the detection limit.[17]

Data on emissions of organics and POMs from CLM-fired sources are not available. Techniques and analytic methods are not well established. And until quantitative, analytical techniques are refined for specific compounds, no definitive statements or conclusions can be made.

3.6 APPLICABLE CONTROL TECHNOLOGIES

This section discusses the various technologies which can be used to control PM, SO_2, NO_x, and trace element air emissions from CWM combustion applications. Many of these technologies are currently used to control emissions from existing coal- and oil-fired boilers. Others are still in the developmental stages but might be viable control options when they become commercially available.

The purpose of this discussion is to determine which potential control technologies are best suited for control of air pollutant emissions from CWM combustion applications. The evaluations include a brief description of each control technology, focusing on the following areas:

- status of development,
- use on existing coal- and oil-fired boilers,
- applicability to CWM-fired units,
- retrofit suitability, and
- demonstrated emission control capability.

Particulate matter control techniques are discussed in Section 3.6.1; techniques used to control both PM and SO_2 are discussed in Section 3.6.2; and NO_x control techniques are discussed in Section 3.6.3. A brief discussion of the techniques which achieve some degree of trace element control follows in Section 3.6.4. Although no techniques have been developed to control POM emissions, they are generally minimized through efficient combustion.

Table 3.6-1 summarizes all the applicable control technologies. The descriptions of the control technologies presented here are intentionally brief and very general. Design and operational aspects of each technology are not included. However, Table 3.6-1 also includes a number of references in which detailed information on the technologies may be found.

Those technologies determined to be best suited for CWM applications are discussed in greater detail later in this report. The environmental impacts of their use on CWM-fired boilers are evaluated in Chapter 4 and cost impacts are evaluated in Chapter 5.

3.6.1 Particulate Matter Control Technologies

There are several PM control technologies currently used on oil- and coal-fired boilers which are potential control options for CWM-fired boilers. These potential technologies are:

- electrostatic precipitators (ESPs),
- fabric filters,
- wet scrubbers,
- mechanical collectors, and
- sidestream separators.

ESPs are the most widely used control device for coal-fired utility and industrial boilers. Many oil-fired utility boilers are equipped with ESPs,

TABLE 3.6-1. CANDIDATE CONTROL TECHNOLOGIES APPLICABLE TO CWM-FIRED BOILERS

Pollutant	Candidate Control Technology	Literature Sources[a]
Particulate Matter	Fabric Filter, ESP, Wet Scrubber, Mechanical Collector, Side Stream Separator.	1. Roeck, D. R. and R. Dennis (GCA Corporation). Technology Assessment Report for Industrial Boiler Applications: Particulate Collection. EPA-600/7-79-178h. U. S. Environmental Protection Agency. Research Triangle Park, NC. December 1979. 2. Environmental Protection Agency. Fossil Fuel Fired Industrial Boilers Background Informtion for Proposed Standards. Preliminary Draft. Research Triangle Park, NC. June 1980. Section 4.1.
SO_2 and SO_2/PM Combined Control	Wet FGD ("throwaway" and regenerable processes).	3. Dickerman, J. C. and K. L. Johnson. (Radian Corporation). Technology Assessment Report for Industrial Boilers: Flue Gas Desulfurization. EPA-600/7-79-178i. U. S. Environmental Protection Agency. Research Triangle Park, NC. November 1979.
	Spray Drying, Dry Injection	4. Reference 2 above; Section 4.2. 5. Kelly, Mary E. and S. A. Shareef (Radian Corporation). Third Survey of Dry SO_2 Control Systems. EPA-600/7-81-097. U. S. Environmental Protection Agency. Research Triangle Park, NC. August 1981.
	Fuel Cleaning Physical Coal Cleaning	6. Buroff, J. et al. (Versar, Inc.) Technology Assessment Report for Industrial Boiler Applications: Coal Cleaning and Low Sulfur Coal. EPA-600/7-79-178c. U. S. Environmental Protection Agency. Research Triangle Park, NC. December, 1979.

TABLE 3.6-1. (Continued) CANDIDATE CONTROL TECHNOLOGIES APPLICABLE TO CWM-FIRED BOILERS

Pollutant	Candidate Control Technology	Literature Sources[a]
NO_x	Combustion Modifications (LEA, staged combustion FGR, low-NO_x burners)	7. Lim, K. J., et al. (Acurex Corporation). Technology Assessment Report for Industrial Boiler Applications: NO_x Combustion Modifications. EPA-600/7-79-178f. U. S. Environmental Protection Agency. Research Triangle Park, NC. December 1979.
		8. Reference 2 above; Section 4.3.
	Ammonia Injection	9. Castaldini, C. et al/Acurex Corporation). Technical Assessment of Thermal De NO_x Process. EPA-600/7-79-117. U. S. Environmental Protection Agency. Research Triangle Park, NC. May 1979.
NO_x	Flue Gas Treatment	10. Jones, G. D. and K. L. Johnson (Radian Corporation). Technology Assessment Report for Industrial Boiler Applications: NO_x Flue Gas Treatment. EPA-600/7-79-178g. U. S. Environmental Protection Agency. Research Triangle Park, NC. December 1979.

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[a] These literature sources are informative summary reports on the technology design and operation on coal and oilfired boilers. The sources also provide many, more detailed, references.

but most industrial boilers firing oil are uncontrolled. Fabric filters are very successful in controlling emissions from coal-fired boilers. They are not used on oil-fired boilers, however, because the hygroscopic nature of resulting fly ash can potentially cause severe bag blinding problems; the oil fly ash particles tend to stick to the bags like tar.

Wet scrubbers are rarely used on oil-fired boilers due to the relatively small particle size of oil fly ash (generally less than 2 micrometers) and the low efficiency of these collectors in removing very small particles. Venturi scrubbers are the most efficient type of wet scrubber for PM control, but their PM collection efficiency is not as high as that of ESPs or fabric filters. And to obtain high efficiency in removing small particle size distributions, the energy requirements (due to large pressure drops) of venturi scrubbers become prohibitive by comparison to ESPs and fabric filters. Although venturi scrubbers are not often used as a sole PM control device, they are often included in wet FGD systems to achieve combined PM and SO_2 control.

As with venturi scrubbers, mechanical collectors achieve a low collection efficiency of small particle sizes and are therefore rarely used on oil-fired boilers. Although mechanical collectors are used on some coal-fired boilers, they serve only as supplemental controls, eliminating the larger particles from the flue gas before it is passed through the primary control device. Sidestream separators are the most recently developed PM control technology and to date have only been used in the automobile industry on coal-fired spreader stokers.[16]

Although any of these control techniques are applicable to CWM- fired boilers, those most efficient in reducing PM emissions from coal combustion are fabric filters, ESPs, and venturi scrubbers. These techniques are expected to be used on boilers firing CWM.

Any of these technologies could be designed into a new installation, provided the overall cost benefit was good. The retrofit suitability of these PM control techniques to existing boilers, however, is dependent on site-specific factors. If the existing boiler is currently using an adequate PM control technology, it might be most feasible to increase the capacity of the existing system. If the existing boiler does not use PM controls, then space availability will be an important factor in determining the feasibility of using a particular control technology. Mechanical collectors have the lowest space requirements; fabric filters and ESPs will require more space. The venturi scrubber itself may not require as much space as an ESP or fabric filter but the necessary sludge handling equipment could make the overall space requirements for a scrubber greater than for other technologies.

3.6.2 Combined SO_2/PM Control Technologies

There are several technologies applicable to CWM-fired boilers which simultaneously reduce PM and SO_2 emissions. Some of these technologies reduce the ash and sulfur content of coal prior to preparation of the CWM, thereby reducing the PM and SO_2 emissions resulting from CWM combustion. The remaining technologies remove PM and SO_2 from the flue gas stream.

Pre-combustion control techniques include beneficiation processes as well as simple blending. These techniques are generally referred to as follows:

- physical coal cleaning
- chemical coal cleaning
- coal blending and use of naturally occurring clean coals (< 1%S).

Physical coal cleaning, coal blending, and the use of naturally occurring clean coals are all currently employed in the coal industry. Chemical coal cleaning is still being developed but is a potential option for future applications. Pre-combustion control techniques differ from post-combustion control techniques in that they are options exercised by the cleaning and CWM preparation facility operators rather than by the boiler operators.

Flue gas desulfurization (FGD) encompasses several post-combustion technologies which reduce both PM and SO_2 emissions. Wet FGD systems currently used on coal- and oil-fired boilers are:

- sodium scrubbing,
- dual alkali, and
- lime/limestone.

In addition to the "throwaway" wet FGD systems mentioned, a few regenerable FGD systems have also been demonstrated.

Dry FGD control technologies, developed more recently than wet FGD, are:

- spray drying, and
- dry injection of sodium-based compounds.

Spray drying FGD is commercially available for use on coal- and oil- fired boilers, but dry injection of sodium-based compounds has only been investigated at the pilot-scale.

3.6.2.1 Physical Coal Cleaning--

Physical coal cleaning (PCC), sometimes referred to as coal preparation or coal washing, is a well-developed technology. Even so, the full potential of physical coal cleaning for industrial and utility steam generation has not been realized. Close to 100 percent of all metallurgical coal (used by the steel industry) is physically cleaned but only about 25 percent of industrial/utility coal is physically cleaned prior to use.[17]

Most existing coal cleaning facilities were designed for ash removal with little incentive, until recently, to remove sulfur. Depending upon the properties of coal handled and the unit operations performed at a particular facility, ash can be reduced by 10-70 percent and pyritic sulfur can be reduced by 35-70 percent.[18,19]

As mentioned in Section 3.2, coal contains two major types of sulfur — mineral (pyritic) and organic. Pyritic sulfur is present in discrete particles which can be removed from the coal by the gravimetric separation techniques usually employed in physical coal cleaning processes. However, organic sulfur is an integral part of the coal matrix and can only be removed by chemical modification of the coal structure.[20] The organic sulfur content of coal accounts for 30-70 percent of the total sulfur and thus bounds the amount of sulfur removal possible by physical cleaning techniques.

Whereas physical coal cleaning is optional for coals to be used in coal-fired boilers, it is almost a mandatory requirement for coals used in the preparation of CWM. The preparation of CWMs demands that the coal have fairly consistent properties for reasons of stability and viscosity control. Coals vary widely in their ash and sulfur contents. Physical cleaning reduces the variability of coal composition and consequently the variability of CWM composition, thus improving the CWM produced. The coal used in preparing CWM should also be free of foreign matter such as quartz and tramp iron; abrasive components such as these are removed during physical coal cleaning.

The coal characteristics and degree of cleaning applied dictate the degree of ash and sulfur removal attainable by PCC alone. In virtually all cases, it will be necessary to use PCC in conjunction with other pre-combustion and/or post-combustion control techniques to meet PM and SO_2 emission regulations. The combinations of various control technologies that can be used to meet EPA emission standards are discussed in Chapters 4 and 5.

Physical coal cleaning is generally conducted at or near the mine site. Thus, there would be no retrofit costs for existing boilers converted to CWM firing. The cost of physical coal cleaning would be reflected in the cost of the prepared CWM, however. Physical coal cleaning increases the cost of coal used in preparing CWM from $2 to $13 per ton depending on the level of cleaning (See Appendix A).

Physical coal cleaning is economically attractive for coals used in preparing CWMs. Up to 50 percent of the cost of conventional PCC is due to energy and equipment requirements for dewatering; for coals used in preparing CWMs, dewatering is not required. Another significant cost element of PCC is grinding. But coal used in CWM must be ground regardless.[21]

3.6.2.2 Chemical Coal Cleaning--

Chemical coal cleaning techniques are still in the developmental stages but should reach full-scale commercialization in 2 to 5 years. Thirty chemical cleaning processes have been identified, with major R&D programs associated with eleven of these processes.[22,23]

Although they do not remove as much ash as physical cleaning techniques, chemical coal cleaning can remove a much higher percentage of sulfur. Most chemical cleaning processes remove up to 90 percent of the pyritic sulfur and several remove up to 40 percent of the organic sulfur.[22] Depending on the ratio of pyritic to organic sulfur, chemical cleaning could reduce the total sulfur content of the coal by 55-70 percent.

A major disadvantage of chemical cleaning compared to physical cleaning is its cost. Annualized chemical cleaning costs are expected to range from $14-30 per ton of clean coal (excluding cost of coal).[24] As mentioned previously, annualized costs for physical cleaning of coal used in CWMs should range from \$2 to \$13 per ton of clean coal (excluding cost of coal).

3.6.2.3 Coal Blending and Use of Naturally Occurring Clean Coals--

The sulfur content of U. S. coals varies greatly with 46 percent of the reserve base classified as low sulfur (<1% S) coal, 21 percent having between 1 and 3 percent sulfur (medium sulfur), and 21 percent containing more than 3 percent sulfur (high sulfur). The sulfur content is not known for 12 percent of the reserve base.[20]

The use of naturally occurring low-sulfur coal in CWM can effectively reduce SO_2 emissions. But even if low-sulfur coal is used in preparing CWM, it is likely that other controls will be required to meet existing SO_2 emissions regulations. Physical coal cleaning will be applied to all coals used in the preparation of CWM, even naturally occurring clean coals. CWMs made with physically cleaned low-sulfur coals should meet existing SO_2 emissions regulations for utility boilers without supplemental controls.

Blends of various types of coal may be used in CWM preparation to achieve desired fuel properties (viscosity, stability, heating value, etc.). Depending upon the coals used, blending may also aid in reducing emissions resulting from CWM-firing.

3.6.2.4 Wet FGD Systems--

There are two categories of wet FGD systems — throwaway and regenerable. Throwaway systems such as sodium scrubbing, dual alkali, and lime/limestone treatment are most commonly used on existing coal- and oil-fired boilers. Regenerable systems represent a relatively newer technology and their use on existing boilers in the U. S. is somewhat limited.

Sodium scrubbing is used almost exclusively on small (<125 MW) industrial boilers with at least 125 such systems currently operating, planned or under construction in the U. S.[25] Dual alkali systems are employed on several coal-fired industrial boilers and five systems for coal-fired utility boilers are planned or operational.[26] Lime and limestone systems account for more than 80 percent of the FGD systems used on coal-fired utility boilers.[26] But their use on industrial boilers is very limited.[27]

All of these wet FGD systems can achieve at least a 90 percent removal of SO_2 if they are properly designed and maintained.[28] Wet FGD systems can also reduce PM emissions to at least 43 ng/J (0.10 lb/10 Btu) for both industrial and utility coal-fired boilers.[28,29]

Although all wet FGD systems remove fly ash as well as SO_2, other means of fly ash collection may be applied concurrently. For example, mechanical collectors placed ahead of the wet FGD systems capture large fly ash particles and help to reduce potential scrubber erosion and plugging. Since physically cleaned coals will be used in preparing CWMs, the ash and sulfur variability of these fuels is reduced. Consequently, the PM and SO_2 loading variability is decreased and should result in improved FGD collection efficiencies. Physical coal cleaning should also reduce the capacity of FGD needed to meet emissions regulations.

Wet throwaway FGD systems themselves require less space than do the regenerable FGD systems. But the overall space requirements for throwaway systems may be greater when waste handling equipment and waste disposal is included. Of the wet FGD systems discussed here, sodium scrubbing is the least complex process. The disposal of the resulting liquid waste, however, might require expensive wastewater treatment to neutralize the highly soluble sodium salts. Dual alkali and lime/limestone systems produce a wet sludge which is generally disposed of in on- or off-site ponds or landfills.

3.6.2.5 Dry FGD Systems--

Spray drying is the newest of the FGD technologies commercially available for the control of PM and SO_2 emissions from coal-fired boilers.

Twelve utility boiler systems and twelve industrial boiler systems are operating or planned.[31] Although dry injection of sodium-based compounds has been investigated at the pilot scale, no commercial applications have yet been planned.[32]

As with wet FGD techniques, spray drying can also achieve a 90+ percent removal of SO_2.[33] And pilot plant test results of dry injection indicate that it too can achieve SO_2 removal efficiencies of greater than 90 percent.[32]

Both spray drying and dry injection include fabric filters to collect fly ash and dry waste solids formed during desulfurization. Fabric filters generally have PM collection efficiencies of 99.9+ percent. In most cases, PM emissions can be reduced to below 21 ng/J (0.05 lb/10^6 Btu) with fabric filter.[34] Neither system produces any liquid waste or wet sludge which must be disposed of.

The spray drying process requires adequate space for the dryer, fabric filter and reagant handling and preparation equipment. Dry injection needs space for the fabric filter and reagant preparation and handling equipment.

3.6.3 NO_x Control Technologies

Control technologies for NO_x can be divided into two groups: (1) combustion modification controls and (2) post-combustion controls.

Combustion modification techniques include:

- low excess air operation (LEA),
- staged combustion,
- flue gas recirculation (FGR), and
- low-NO_x burners.

Thermal NO_x formation can be effectively reduced by combustion modifications that reduce the reacting components (e.g., low excess air), decreases combustion residence time, or lower the combustion flame temperature. These techniques are also effective in reducing some fuel NO_x emissions. Post-combustion controls include ammonia injection ("thermal De-NO_x") and flue gas treatment techniques.

3.6.3.1 Low Excess Air (LEA)--

Low excess air operation involves reducing the amount of excess combustion air supplied to the boiler. In most cases, this technique can be easily implemented on existing units. In addition to moderately reducing NO_x emissions, LEA can improve boiler efficiency and reduce fuel costs.

Equipment requirements for LEA operation include flue gas O_2 and CO_2 monitor systems and low air flow alarms. Compartmental windboxes may be required for multiburner units to assure proper air flow distribution.[35] Air flow levels must be maintained above minimum levels to avoid increases in smoke, CO, or unburned hydrocarbon emissions.

3.6.3.2 Staged Combustion--

Staged combustion involves injecting a portion of the combustion air through ports located downstream of the burner(s). This practice reduces the air-to-fuel stoichiometry near the burner when fuel nitrogen volatilization occurs, and is effective in controlling formation of fuel NO_x. Because it is more effective in reducing fuel NO_x, staged combustion achieves greater overall NO_x reductions than LEA for coal-based fuels which emit significant quantities of fuel NO_x. Staged combustion has been demonstrated and used commercially on large field-erected pulverized coal-, oil-, and gas-fired industrial boilers. In California, staged combustion is used on some residual oil- and gas-fired utility boilers larger than 73 MW (250×10^6 Btu/hr) to help meet state and local NO_x regulations for existing boilers.[35]

The effectiveness of staged combustion depends strongly on proper location of the secondary air ports. The optimum location may vary with boiler type and size. Retrofit of staged combustion air ports may not be feasible on some boilers, especially package units.

An alternative to modifying the boiler to accommodate secondary air injection ports is called "burners-out-of-service" (BOOS). With this technique the secondary air is injected through downstream burners that have been taken out of service (i.e. no fuel is supplied to these burners). Proper implementation of BOOS requires careful selection of the in-service burner pattern and close control of the air flow. As with all staging techniques, BOOS will require derating of the boiler unless the fuel delivery system is modified.[36] The amount of derating depends on the degree or severity of staging and current excess boiler capacity.

As with LEA, flue gas O_2 and CO_2 monitors and automatic air control systems are recommended for staged combustion. Since effectiveness of staging can only be measured with monitoring, these monitors are recommended to reduce smoking and CO formation and to increase boiler efficiency.

3.6.3.3 Flue Gas Recirculation (FGR)--

The flue gas recirculation technique is based on returning a portion of the flue gas to the furnace through the burner windbox. The recirculated flue gas absorbs some of the heat released during combustion and acts as an oxygen diluent, lowering the bulk furnace gas temperature, and resulting in reduced thermal NO_x formation. FGR, which does not reduce fuel NO_x, will not be as effective in reducing NO_x from CWM combustion as it is in reducing NO_x from gas- and distillate-oil firing. This is due to the contribution of fuel nitrogen (fuel NO_x) to total NO_x emissions from CWM.

FGR is commercially available and applicable to gas- and distillate oil-fired industrial boilers. In 1978, FGR was installed on two new 15 MW (50×10^6 Btu/hr) package gas/oil-fired boilers in Southern California.[37] However, FGR is used on few, if any, existing residual oil-fired boilers.

Implementation of FGR requires extra fan capacity and ducting. Also, burners and windboxes must be modified for the increased gas flow. FGR will be relatively more difficult and costly to retrofit to most existing oil-fired boilers than LEA or staged combustion.

Proper air flow and recirculation gas flow control must be incorporated to maintain good combustion and flame stability.

3.6.3.4 Low-NO_x Burners--

New burner designs, labeled low-NO_x burners, are being developed for controlled mixing of air, fuel, and combustion products within the flame zone to reduce NO_x formation. Low-NO_x burners developed for gas- and oil-firing generally use a combination of cooling and staging.[37] Flame surface area is increased for greater heat dissipation; burner- area gas recirculation is used to cause rapid quenching of the flame and cool the combustion process; and controlled air/fuel mixing is used to provide a staged combustion effect. Thus, the low-NO_x burner should be effective in reducing both thermal and fuel NO_x, and can usually achieve greater NO_x reductions than LEA, staged combustion, or FGR.

Low-NO_x burners are an important NO_x reduction technique since they save the cost of supplying overfire air (OFA) ports and reduce the penalty of derating that accompanies staging techniques. In addition, many industrial boilers have only one burner, making conventional staging technqiues such as burners-out-of-service (BOOS) impossible.

Low-NO_x burners are required as "best available control technology" for new residual oil-fired boilers in at least two states (California and Texas). However, their use on existing oil-fired boilers is not widespread since low-NO_x burners are a relatively new technology, having only recently been applied to commercially operating boilers.[37]

Retrofit of low-NO_x burners to existing boilers should be feasible in many cases. However, care must be exercised in selecting the proper low-NO_x

burner design for an existing boiler. For example, almost all low-NO_x burner designs under development may result in an extended flame zone, leading to flame impingement on the back wall of the boiler if the firebox is not large enough.[37] The amount of flame zone extension is variable depending upon each specific application.

3.6.3.5 Ammonia Injection--

Ammonia injection involves the non-catalytic reduction of NO_x in the flue gas to nitrogen and water. Ammonia is used as the reducing agent. The technique is often referred to as selective non-catalytic reduction or thermal De-NO_x (as developed by Exxon). The effectiveness of the technique is highly dependent on the temperature at the point where the ammonia is injected into the boiler. Specifically, up to 40 percent NO_x reduction can occur if the temperature is between 1200 and 1260K (1700° to 1800°F); outside the range of 1175 to 1350K (1655° to 1970°F), however, less than 10 percent of the NO_x can be reduced to nitrogen and water.[37]

Although the ammonia injection technique is commercially offered, it is not widely applied to domestic operating industrial boilers. Ammonia injection is scheduled for application on large residual oil- fired utility boilers in Southern California by 1982.[37]

The required reaction temperatures for noncatalytic NO_x reduction are found in different areas of the boiler depending on boiler design and operating load. For example, at full load the desired temperatures may be found in the convective section of the boiler. But changing boiler load causes a shift in temperature profile through the boiler, and optimum temperatures may occur at another location. To avoid curtailment of boiler load-following capability it may be necessary to install multiple injection grids. This technique, however, has not been demonstrated[37] and may be infeasible to retrofit to existing boilers.

Sulfur containing fuels also present a potential problem for ammonia injection. The formation of ammonium sulfate or ammonium busulfate can cause plugging of an air preheater or corrosion of boiler parts. Additionally, to assure that ammonia emissions to the atmosphere are minimized, ammonia sensors and feedback control systems for the injectors will be required.[37]

3.6.3.6 Flue Gas Treatment (FGT)--

Post-combustion flue gas treatment techniques for control of NO_x emissions use either a gas phase reaction or liquid absorption to reduce NO_x. The primary NO_x FGT processes are:

- selective catalytic reduction (SCR),
- wet scrubbing (for NO_x and SO_2), and
- electron beam irradiation.

None of these processes has been applied to commercially operating industrial or utility boilers in the U. S. Development of wet scrubbing processes for combined SO_2/NO_x removal has not progressed beyond the pilot-scale stage and the electron beam irradiation process is in the pilot-scale stage. The earliest domestic commercial applications of SCR are planned for 1982 on two low sulfur oil-fired boilers in Southern California. SCR has been applied to fired heaters in refinery service and is currently operating effectively on oil and gas utility boilers in Japan. The successes in Japan have prompted California to base its proposed NO_x limit of 40 ng/J (0.09 $lb/10^6$ Btu) for coal-fired power plants on implementation of SCR.[38] Even so, FGT is not generally as attractive as combustion modification techniques due to its higher cost. Only when NO_x reductions of 80-90 percent, or higher, are required is FGT used as a NO_x control technique.

3.6.4 Trace Element Control

The same technologies used to control particulate matter are also effective in reducing emissions of trace elements. Physical coal cleaning is a very effective means of removing trace elements prior to combustion.

Physical coal cleaning should remove significant amount of all trace elements except beryllium. Small fly ash particles resulting from CWM combustion contain most of the trace element emitted in the flue gas. Fabric filters, ESPs, and venturi scrubbers are effective in controlling these small particles. However, some trace elements, primarily mercury and selenium, remain in the vapor phase. These emissions are best controlled using wet scrubbing techniques, if physical coal cleaning does not achieve adequate removal.

3.7 SUMMARY OF CONTROL TECHNOLOGIES SELECTED FOR FURTHER EVALUATION

Table 3.7-1 shows the emission control techniques applicable to CWM-fired boilers that have been selected for further evaluation. The criteria used in selecting technologies for further evaluation included:

- effectiveness in controlling PM, SO_2 or NO_x emissions,
- status of development,
- retrofit suitability, and
- multipollutant control capability.

The environmental and cost impacts of ESPs and fabric filters will be discussed in subsequent chapters. These technologies were selected for further evaluation based on their effectiveness in controlling PM emissions from coal-fired boilers and their retrofit suitability. Wet scrubbers, mechanical collectors, and side stream separators will not be further evaluated as PM control devices for CWM-fired boilers. Wet scrubbers were not selected for further evaluation due to their low collection efficiencies for small particle sizes. But, wet scrubber FGD systems used for combined PM/SO_2 control will be further evaluated. Mechanical collectors were not selected for further evaluation because they are used only as a supplemental control technique. Sidestream separators were not selected since their suitability for liquid fuels, including CWM, has not been determined.

TABLE 3.7-1. CONTROL TECHNOLOGIES SELECTED FOR FURTHER EVALUATION

Pollutant	Control Technologies to be Evaluated[a]
PM	Fabric Filter ESP
SO_2/PM	Physical Coal Cleaning Wet FGD ("throwaway" systems-dual alkali, lime/limestone, sodium) Spray Drying Dry Injection
NO_x	LEA Staged Combustion FGR Low-NO_x Burners Flue Gas Treatment

The combined PM/SO_2 control techniques selected for further evaluation were:

- physical coal cleaning,
- throwaway wet FGD,
- dry scrubbing FGD, and
- dry injection of sodium-based compounds.

The technologies not selected for further evaluation were:

- chemical coal cleaning,
- coal blending and use of naturally occurring clean coals, and
- regenerable wet FGD systems.

Chemical coal cleaning was not selected for further evaluation because it is still in the developmental stages. The expected costs of chemical coal cleaning are also significantly higher than those of physical coal cleaning. Although coal blending and low-sulfur, low-ash coals are considered in subsequent chapters, they are not evaluated as stand-alone control techniques. Even run-of-mine clean coals will be beneficiated using physical coal cleaning techniques prior to their use in CWMs. Regenerable FGD systems were considered too costly for retrofit to existing oil-fired boilers converted to CWM.

All of the NO_x control technologies discussed in this chapter will be evaluated further in subsequent chapters. These NO_x control technologies are:

- low excess air (LEA),
- staged combustion,
- flue gas recirculation (FGR),
- low-NO_x burners, and
- flue gas treatment processes.

A detailed discussion of the environmental impacts of selected control techniques is presented in Chapter 4. Cost impacts are presented in Chapter 5. The evaluations are presented for pre-combustion techniques for the control of PM and SO_2, combustion modification techniques for the control of NO_x, and post-combustion techniques for the control of PM, PM/SO_2, or NO_x. The effects of these PM, SO_2, and NO_x control techniques on trace elements emissions are also discussed.

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CHAPTER 4

ENVIRONMENTAL IMPACTS OF CONTROL TECHNOLOGIES

The environmental impacts of various technologies used for the control of particulate matter (PM), SO_2, and NO_x from CWM-fired boilers are presented in this chapter. The environmental impacts of the technologies are evaluated in terms of: (1) the effectiveness of the technology in controlling one or more of the criteria air pollutants (PM, SO_2, NO_x), (2) secondary environmental impacts of the technology, including liquid and solid wastes, and (3) the effectiveness of the technology in controlling trace elements (As, Be, Cd, Cr, Hg, Mn, Ni, Se, and V) emissions.

Section 4.1 summarizes the environmental impacts of the various PM, PM/SO_2, and NO_x control technologies. Sections 4.2 through 4.6 provide detailed analysis of each pre-combustion, combustion modification, and post-combustion control technology. The effects of these technologies on trace element control are discussed in Section 4.7.

4.1 SUMMARY OF ENVIRONMENTAL IMPACTS

Little or no data are available concerning the environmental impacts of control technologies for CWM combustion. For this reason, emission control data and information pertaining to applications of the technologies to coal-fired boilers are used in this evaluation. CWM combustion should be similar to coal combustion, but there are also some important differences. Differences which might affect the performance of the control technologies are identified and evaluated in terms of their qualitative effects on performance.

TABLE 4.1-1. ENVIRONMENTAL IMPACTS OF CONTROL TECHNOLOGIES FOR CWM COMBUSTION

Table 4.1-1a. Emission Reduction Capability of Candidate Control Technologies

Control Technology	CWM Emissions Control[a]			Comments
	PM	SO_2	NO_x	
Fabric Filters	99+% removal; 22ng/J (0.05 lb/10^6 Btu)	-[b]	-	Can reduce PM emissions to "oil-only" levels or less.
Electrostatic Precipitators	99=% removal; 43 to 14 ng/J (0.1 to 0.03 lb 10^6 Btu)	-	-	Effectiveness depends on adequate collection plate area. Lack of CWM fly ash resistivity data. With proper design, can reduce PM emissions to "oil-only" levels or less.
Wet Scrubber (venturi-type)	Up to 90% removal; 43 ng/J (0.1 lb/10^6 Btu)	-[b]	-	Can reduce PM emissions to "oil-only" levels. Produces wet sludge for disposal; possible liquid waste impacts.
Wet FGD (Sodium throwaway, dual alkali, lime, limestone)	Up to 98+% removal; 43 ng/J (0.1 lb/10^6 Btu)	90% removal		Can reduce SO_2 and PM emissions to "oil-only" levels. Potentially large amounts of sludge for disposal depending on boiler size, SO_2 removal. Potentially significant liquid waste impacts for sodium throwaways. Reduced plume dispersion without reheat.

Table 4.1-1a. (Continued) Emission Reduction Capability of Candidate Control Technologies

Control Technology	CWM Emissions Control[a] PM	CWM Emissions Control[a] SO_2	CWM Emissions Control[a] NO_x	Comments
Spray Drying FGD (lime sorbent; includes fabric filter or ESP)	99+% removal; 22 ng/J (0.05 lb/10^6 Btu) or less.	Up to 90% removal.	-	Can generally reduce SO_2 and PM emissions to "oil-only" levels. SO_2 removal may be less for high sulfur CWM.
Dry Injection FGD (sodium-based alkali; includes fabric	99+% removal; 22 ng/J (0.05 lb/10^6 Btu) or less	Up to 90% removal.	-	Can generally reduce SO_2 and PM emissions to "oil-only" levels. SO_2 removal may be less for high sulfur COMs. Potentially more severe solid waste impacts due to solubility of sodium-based wastes.
Physical Coal Cleaning	10 to 70% reduction in coal ash content.	Up to 70% sulfur removal with extensive cleaning.	-	Can achieve SO_2 levels of "oil-only" depending on final coal sulfur. Most effective at removing sulfur from coals with high pyritic/organic sulfur ratios. Will likely require additional PM control.

Table 4.1-1a. (Continued) Emission Reduction Capability of Candidate Control Technologies

	CWM Emissions Control[a]			
Control Technology	PM	SO_2	NO_x	Comments
Low NO_x Burners[c]	-	-	Reductions vary with burner type, design and with CWM composition; NO_x reductions of at least 50% possible.	Has been shown to achieve NO_x levels equal to or less than oil-only in limited laboratory tests.
Staged Combustion[c]	-	-	30 to 40% reduction in NO_x.	Effective in reducing fuel NO_x. Not likely to achieve oil-only levels in all cases.
Low Excess Air[c]	-	-	10 to 20% reduction in NO_x.	Not likely to achieve "oil-only" NO_x levels. Effectiveness depends on CWM properties and boiler design.
Flue Gas Recirculation[c]	-	-	Difficult to quantify because of variability in limited data.	Unlikely candidate for CWM combustion since it is primarily effective on thermal NO_x emissions.

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[a] Control capability described in terms of removal efficiency and/or controlled emission rates achievable.

[b] Fabric filters used in dry injection and spray drying systems to achieve PM control; Wet scrubbers used in FGD systems for combined SO_2/PM control.

[c] Reductions based on limited testing of COM combustion.

Table 4.1-1b. Potential Secondary Environmental Impacts of Control Technologies for CWM Combustion

Control Technology	Type and Nature of Wastes			Other Potential Environmental Impacts
	Dry Solid	Sludge	Liquid	
Fabric Filters	Dry fly ash; established disposal techniques such as landfilling are environmentally acceptable.	-	-	-
Electrostatic Precipitators (ESP)	Same as fabric filter.	-	-	-
Wet FGD (Sodium)	-	-	Liquid waste dissolved sodium salts; may require wastewater treatment or evaporation ponds.	Cooling of flue gas; reduced plume dispersion without reheat.
Wet FGD (dual alkali, lime)	-	Calcium-based in 30-60% solid sludge; landfilling, ponding are environmentally acceptable disposal methods. Commercial utilization may be possible.	Should be minimal with closed-loop operation.	Cooling of flue gas; reduced plume dispersion without reheat.

Table 4.1-1b. (Continued) Potential Secondary Environmental Impacts of Control Technologies for CWM Combustion

Control Technology	Type and Nature of Wastes			Other Potential Environmental Impacts
	Dry Solid	Sludge	Liquid	
Spray Drying (lime sorbent)	Fly ash and calcium-based solids; landfill disposal.	-	-	Some cooling of flue gas, but not as much as with wet FGD because flue gas is not saturated.
Dry Injection (sodium sorbents)	Fly ash and sodium-based salts; high solubility of solids may require specialized disposal methods.	-	-	-
Physical Coal Cleaning	No boiler-site impacts.	-	-	PCC plants covered by existing environmental regulations for fugitive emissions, water, and other impacts.
NO_x Combustion Modifications (LEA, SC, FGR, low-NO_x burners)	-	-	-	May result in high CO_2 unburned hydrocarbons emissions if not properly operated. Problems can be eliminated or minimized with automatic oxygen control systems.

Table 4.1-1c. Trace Element Control Capability of Control Technologies for CWM Combustion

Control Technology	Control of Trace Elements in Classes 2 & 3[a]	Control of Trace Elements in Class 4[b]
Fabric filters[c]	99+% removal of trace elements.	Less control than for Class 2 and 3 elements.
ESP	95+% in many cases.	Less control than for Class 2 and 3 elements.
Wet Scrubber[d]	95+% based on limited data. May be less efficient than fabric filters or ESPs.	Possible improved control over fabric filters or ESPs, since gas becomes saturated.
PCC	About 10 to 75% depending on coal type, PCC process and type of trace element.	25 to 52% depending on coal type, PCC process.

[a] Class 2 and Class 3 elements are those elements that tend to be enriched on smaller fly ash particles (As, Be, Cd, Cr, Ni, Se, V).

[b] Class 4 trace elements are those that tend to remain in the vapor phase. (Hg, Se).

[c] Also applies to spray drying and dry injection systems using a fabric filter.

[d] Applies to wet scrubbers used for PM-only or combined SO/PM removal.

The environmental impacts of several control technologies suitable for CWM-fired boilers are listed in Table 4.1-1. The capability of each technology to reduce criteria pollutant emissions to levels typical of oil-fired boilers is given in Table 4.1-1.

PM Control--

ESPs and fabric filters have each demonstrated particulate matter (PM) collection efficiencies of greater than 98 percent. In nearly every case, these techniques are capable of reducing PM emissions to 43 ng/J (0.10 lb/10^6 Btu) and, in many cases, to 13 ng/J (0.03 lb/10^6 Btu).

Fabric filters are considered the most effective means of controlling PM emissions from coal-fired boilers. They should be equally as effective when applied to CWM-fired boilers. However, fabric filters are not generally used for oil-firing and should probably be avoided if multi-fuel-firing capability is desired.

ESPs are effective in controlling emissions from both coal-fired and oil-fired boilers. But there are no data available concerning the resistivity of CWM fly ash. If different from coal fly ash, ESP performance could be significantly altered when used on a CWM boiler.

ESPs and fabric filters both generate a dry, solid waste. This waste has been designated by EPA as "non-hazardous" and is usually disposed of by landfilling.

Combined PM/SO_2 Control--

Combined PM/SO_2 control can be achieved by both pre-combustion and post-combustion techniques. Physical coal cleaning (PCC) is a pre-combustion control technique employed by the coal/CWM producer. Post-combustion techniques for the control of PM/SO_2 include wet FGD systems, spray drying FGD, and dry injection of sodium-based compounds.

Some degree of physical coal cleaning will be applied to all coals used in the preparation of CWMs. PCC removes ash and sulfur from the coal prior to combustion, thereby reducing the resulting PM and SO_2 emissions. But, depending on the coal characteristics and the level of cleaning performed, additional post-combustion PM/SO_2 controls may be required to meet state and Federal emission limits.

Pre-combustion control techniques reduce the variability of the ash and sulfur content of the CWM product. With more consistent CWM compositions, both the boilers and post-combustion control systems operate more efficiently. As a result, the need for overdesigning the control systems is minimized. Another advantage of pre-combustion control techniques is that they can reduce the need for costly post-combustion control systems. For example, by reducing the ash content of the coal used in CWM, the solid waste disposal requirements of post-combustion systems can be significantly reduced. Since physical coal cleaning takes place at the mine site, there are no adverse environmental impacts to the boiler site. But the coal cleaning/CWM preparation facilities themselves will be subject to existing environmental regulations for fugitive emissions, water, and other impacts.

Of the post-combustion control technologies, wet FGD is the most effective means of SO_2 removal. It has been applied successfully to both industrial and utility boilers firing coal or oil. Dual alkali, sodium scrubbing, and lime/limestone processes are the most commonly used with FGD systems. They typically achieve 90 percent removal of SO_2.

Many of the wet FGD systems are also designed to reduce PM emissions. Venturi scrubber/wet FGD systems are most often used for combined PM/SO_2 control. In some cases, a mechanical collector is placed upstream of the PM/SO_2 scrubber to remove large PM particles before they enter the scrubber, resulting in improved scrubber performance and reliability.

Wet FGD systems generate wet sludges which have potential liquid and solid waste impacts. Another problem associated with the use of wet FGD systems is that the flue gas becomes saturated, reducing plume buoyance and adversely affecting dispersion of gaseous pollutants (NO_x and SO_2). In some cases, reheat must be supplied to improve pollutant dispersion.

Many spray drying systems which have been sold for commercial use have SO_2 removal guarantees of up to 90 percent. Dry injection of sodium-based compounds has not been commercially implemented, but small scale tests show that it can achieve significant SO_2 removal efficiencies. Both spray drying and dry injection include fabric filters (or ESPs for spray drying) downstream for the collection of particulate matter. The disposal of highly soluble sodium-based wastes from dry injection may present more serious solid waste disposal problems than the disposal of calcium-based wastes from spray drying or conventional wet FGD systems.

NO_x Control--

As shown in Section 3.3, NO_x emissions from CWMs are lower than emissions from the parent coal used in preparing the CWM. But it is questionnable whether NO_x emissions from CWM combustion will be lower than from oil-only firing. Low-NO_x burners are expected to be the most effective means of lowering NO_x emissions. Low-NO_x features are expected to be incorporated in CWM-burner design as CWM technology emerges. Low- NO_x burners typically incorporate combustion modification techniques such as staged combustion and low-excess air operation within the burner design. These two techniques are effective in reducing fuel NO_x formation. Another combustion modification, flue gas recirculation (FGR), is primarily used to reduce thermal NO_x emissions and is not expected to be widely applied to CWM boilers. Flue gas treatment (FGT) such as selective catalytic reduction has been demonstrated in Japan and is the basis of the proposed NO_x emissions limit for California. These techniques are capable of efficiencies of 90 percent.

In general, combustion modifications involving low excess air are capable of reducing NO_x emissions from 10 to 20 percent and reductions of up to 40 percent are possible for staged combustion techniques. NO_x reductions with low-NO_x burners will depend upon the particular burner design but can exceed 50 percent. Some other impacts of combustion modification can include a slight increase in smoke and CO formation and in residual hydrocarbon in the exiting stream. These emissions result from lower combustion efficiencies associated with poor control of excess air. FGT can provide up to 90 percent control of NO_x emissions as an add-on control system. One potential secondary impact of FGT is the emission of ammonia since it is used in many NO_x flue gas treatment processes.

It should be noted that the effects on NO_x emissions of variables such as CWM properties, the presence of water in the CWM, combustion air preheat temperatures, and boiler heat release rate from CWM combustion are not fully quantifiable based on existing data. Also, boiler-to-boiler variations in burner and furnace design may result in significant variations in NO_x emissions from combustion of a given CWM.

Trace Element Control--

Many of the trace elements in CWM tend to be enriched on the smaller fly ash particles (Class 2 and 3). The technologies that achieve the greatest degree of fine particulate control are also the most efficient for trace element collection. Therefore, fabric filters, ESPs, and wet scrubbers achieve a high degree of trace element control. Physical coal cleaning is also an efficient means of control since many of the trace elements are removed from the coal along with ash and other mineral constituents. But trace elements in solid or liquid wastes can create potential leaching problems if improper disposal techniques are employed.

4.2 PRE-COMBUSTION TECHNIQUES FOR PM/SO_2: PHYSICAL COAL CLEANING

This section discusses the PM and SO_2 reduction capabilities of physical coal cleaning (PCC), a pre-combustion control technique employed by coal/CWM producers. Physical coal cleaning reduces the ash and sulfur content of coals used to prepare CWMs and consequently reduces the PM and SO_2 emissions from CWM combustion. It is expected that PCC will be applied to all coals used in CWMs.

4.2.1 Pollutant Control Capability

Physical coal cleaning can be defined generally as the separation of waste or unwanted "refuse" materials from coal by techniques based on differences in the physical properties of coal and refuse.[1] Refuse which can be removed by PCC includes ash, pyritic sulfur, quartz, and tramp iron. Crushing the run-of-mine (ROM) coal liberates the refuse from the coal particles. Due to the differences in density of coal and refuse, the refuse can be removed from the coal using various methods. The conventional method of removing dense refuse material from coal is by gravity separation. Other removal techniques include froth flotation, oil agglomeration, and high gradient magnetic separation.

Each coal cleaning facility is unique in its treatment of coal. Each particular cleaning process depends upon the characteristics of the coal to be treated and the desired specifications for the cleaned coal. Five levels of PCC have been described:[2]

Level 1 - Crushing and screening only;
Level 2 - Cleaning of coarse size fraction only;
Level 3 - Cleaning of coarse and medium size fractions;
Level 4 - High efficiency separation to clean all size fractions; and
Level 5 - High efficiency separation to clean all size fractions and produce a high-quality and a medium-quality product.

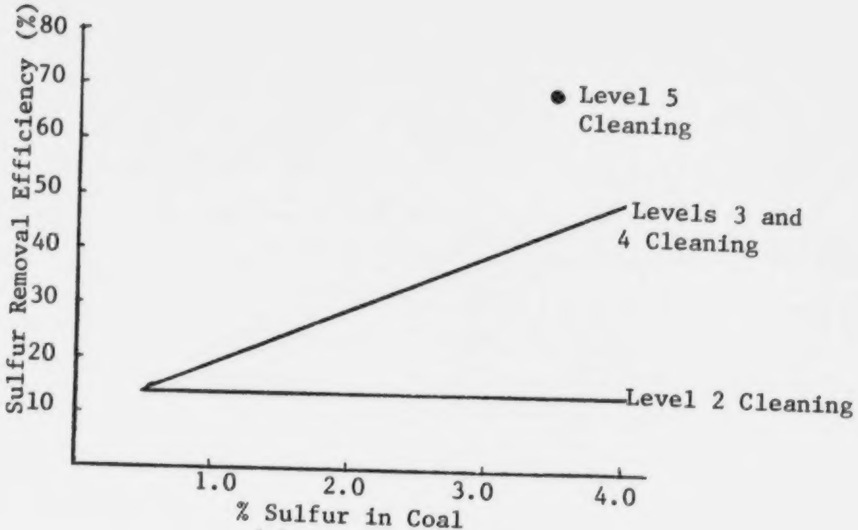
Levels 1 to 3 have traditionally been used in the preparation of steam coals. Level 4 cleaning is typically used to produce the high quality metallurgical coal used by the steel industry. And to date, only one Level 5 facility is in operation as an experimental facility.

The performance of a particular PCC facility is dependent upon the "washability" of the coal and the unit processes employed. Figures 4.2-1a and b show the sulfur and ash reduction potential of various levels of cleaning as a function of ROM coal ash and sulfur content. Figure 4.2-1a indicates sulfur removal capabilities ranging from 13 percent for Level 2 cleaning up to 70 percent for Level 5 cleaning. Ash removal capabilities range from 10 to 75 percent, as shown in Figure 4.2-1b. These figures were developed using data from two sources[3,4] and may not be representative of all coal types and cleaning facilities. The actual ash and sulfur removal capabilities of a particular PCC facility can only be determined by a site-specific, coal-specific evaluation.

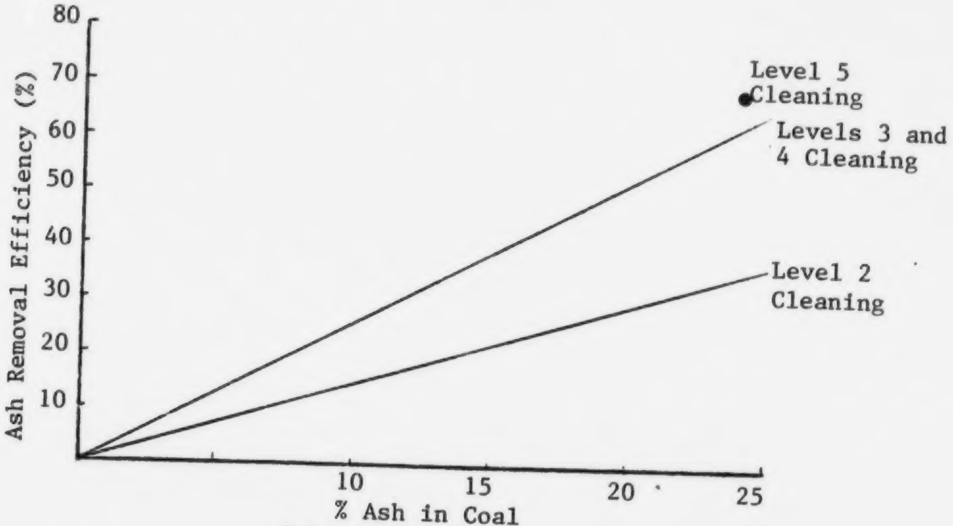
It is unlikely that physical coal cleaning alone will reduce ash content to levels such that no post-combustion PM controls are required to meet air pollution regulations. In many cases, however, PCC can reduce the sulfur content of the coal to a level such that no additional SO_2 controls are required. Even if PCC alone cannot achieve adequate PM and SO_2 control, it can substantially reduce the amount of costly post- combustion control required. PCC also serves to reduce the variability of CWM composition, allowing tighter design specifications to be made. As a result, boiler efficiency and post-combustion control effectiveness can be improved. Table 4.2-1 presents the potential PM and SO_2 emissions of representative physically cleaned coals as compared to ROM coals.

4.2.2 Secondary Environmental Impacts

Physical coal cleaning reduces the quantities of fly ash/bottom ash and wet sludge generated at the boiler site. However, liquid and solid wastes



(a) Sulfur Removal



(b) Ash Removal

Figure 4.2-1. Physical coal cleaning performance as a function of ash and sulfur content.

TABLE 4.2-1. POTENTIAL SO_2 AND PM EMISSIONS FROM CWMs PREPARED WITH RUN-OF-MINE AND CLEANED COAL[a,b]

Coal	Level of Cleaning	HHV		Ash	S	Uncontrolled PM Emissions		Uncontrolled SO_2 Emissions	
		kJ/kg	(Btu/lb)	wt.%	wt.%	ng/J	(lb/10^6 Btu)	ng/J	(lb/10^6 Btu)
High-Sulfur Eastern	ROM	21,100	(9,056)	8.1	2.7	3,096	(7.2)	2,580	(6.0)
	3 & 4	22,293	(9,568)	5.6	1.5	2,021	(4.7)	1,376	(3.2)
	5	23,806	(10,217)	2.4	0.81	817	(1.9)	688	(1.6)
Low-Sulfur Eastern	ROM	23,095	(9,912)	4.9	0.64	1,720	(4.0)	559	(1.3)
	2	23,286	(9,994)	4.4	0.56	1,505	(3.5)	473	(1.1)
Low-Sulfur	ROM	19,769	(8,485)	4.8	0.53	1,935	(4.5)	516	(1.2)
	2	19,933	(8,555)	4.3	0.46	1,720	(4.0)	473	(1.1)

[a] See Appendix B for the ultimate analysis of the various coals.

[b] Ash and sulfur removal efficiencies determined from Figure 4.2-1.

are associated with the PCC process itself. The net effect of PCC is one of increased solid waste due to the removal of refuse (valuable combustible matter and undesired inorganic materials). Depending upon the cleaning process and coal composition, from 5 to 50 percent of the coal is lost as refuse. A detailed discussion of the liquid wastes associated with physical coal cleaning can be found in Reference 3, pages 555-562. Some facilities are minimizing liquid waste disposal requirements by recycling process water.

Physical coal cleaning facilities are subject to EPA standards for air (fugitive emissions), water quality, and MSHA/OSHA regulations for refuse disposal.

4.3 COMBUSTION MODIFICATIONS FOR NO_X REDUCTION

As discussed in Section 3.3, the total NO_x emissions from combustion result from the formation of thermal NO_x and from the formation of fuel NO_x. Various modifications to the boiler and operating procedures can effectively reduce emissions of NO_x by modifying combustion characteristics. This section examines four combustion modification techniques which are applicable to controlling NO_x emissions from boilers firing CLM. The techniques discussed here include use of low excess air (LEA), staged combustion (SC), flue gas recirculation (FGR), and low-NO_x burners. They are evaluated with respect to NO_x control capability and the potential secondary environmental impacts associated with application of the control technique.

The precise estimation of control effectiveness of any type of combustion modification is quite site-specific for a number of reasons. Particular burner and furnace design greatly impact NO_x emissions from the combustion process. In addition to the variability of existing burners and boilers, the variability in the properties of potential fuel mixtures makes determination of NO_x emissions and controllability difficult to establish. Finally, the available test data are extremely limited with respect to CWM

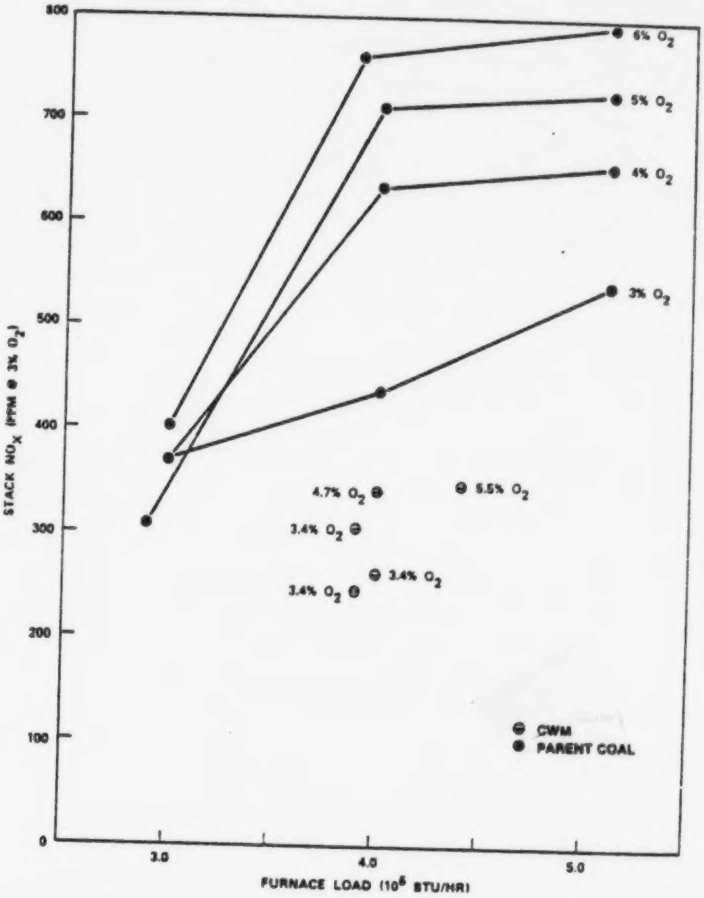


Figure 4.3-1. NO$_x$ emissions from CWM combustion tests.[5]

firing. One set of tests, shown in Figure 4.3-1, indicate that NO_x emissions from CWM combustion are lower than emissions from combustion of the parent coal. A conclusion of this same study was that emissions from CWM combustion are expected to be similar to emissions from combustion of moist coal. Therefore, the combustion modifications for NO_x reduction are presented in the context of COM and coal combustion studies.

4.3.1 Low Excess Air

By reducing the amount of excess air to the combustor, the amount of available oxygen is reduced, as well as the furnace temperature. As a result, both thermal NO_x formation and fuel NO_x formation are suppressed. This is evidenced by the family of curves in Figure 4.3-1 for the CWM parent coal combusted in the laboratory furnace. And, in Figure 4.3-2, the relationship is evident for the combustion of pulverized coal in a 200-MW arch-fired utility boiler. The emissions presented in this figure also indicate the effectiveness of the arch-fired furnace in reducing NO_x formation since this furnace design includes a large furnace box and results in a slowly mixing diffusion flame (lower flame temperatures).

Figure 4.3-3 presents the results of low excess air testing on coal combustion units in Japan, and indicates this same trend of lower NO_x emissions with decreasing oxygen.

The minimum amount of LEA possible for boilers is limited, however, by the CO and smoke formation resulting from LEA. Minimum practical levels of LEA range from 15 percent for new coal-fired utility boilers to 20 percent for some older units. LEA is generally incorporated as a design and operating feature since it increases boiler efficiency.

There are some potential drawbacks to implementing LEA for NO_x reduction. The reduced amount of excess air affects the combustion process and combustion efficiency. Smoke and CO formation at near- minimum LEA

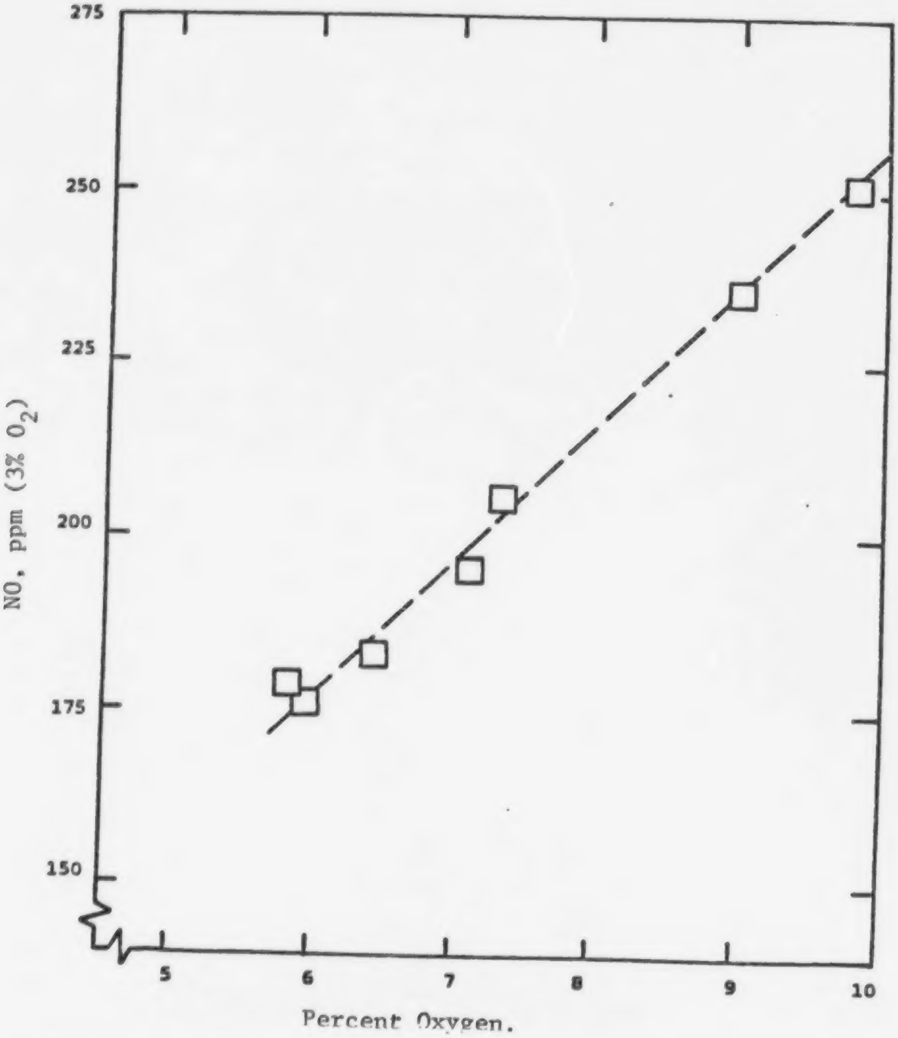
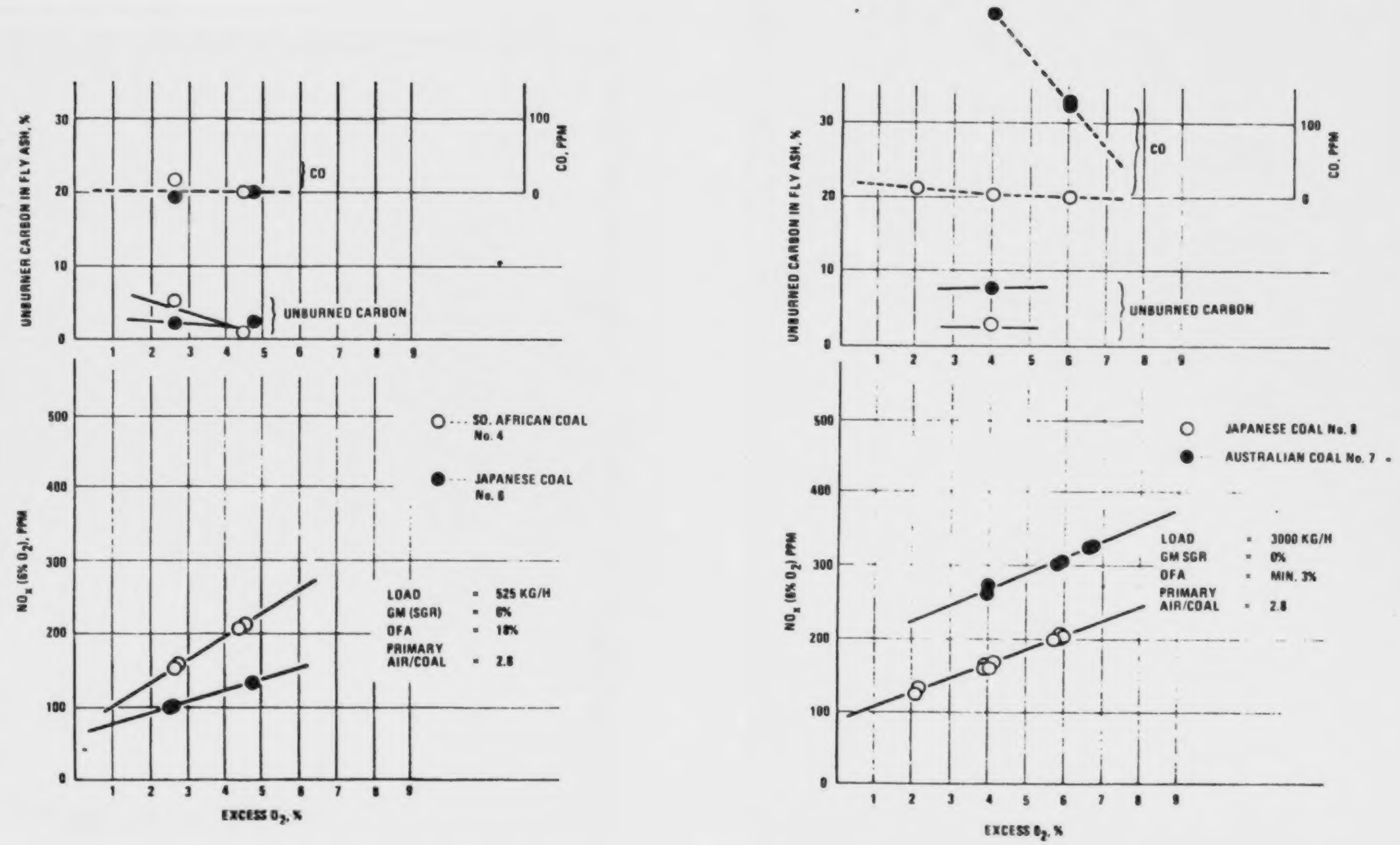


Figure 4.3-2. NO_x emissions from a 200 MW arch-fired pulverized coal utility boiler.[6]



a. 525 kg/hr (1158 lb/hr)

b. 3,000 kg/hr (6615 lb/hr) → 6615

Figure 4.3-3. NO$_x$ emissions with excess oxygen - SGR test burner at two loads.[7]

levels could become too severe as a result of incomplete combustion. Incomplete combustion may result in increased POM emissions, as indicated in Figure 4.3-4.[8] Boilers can be supplied with an automatic oxygen control system so that these potential problems are minimized or even eliminated.[9] Another drawback with LEA implementation is a reduction in boiler efficiency. At low excess air levels, there is also residual hydrocarbon in the exhaust gas stream.

These same potential secondary impacts are also applicable to other NO_x combustion modifications. The combustion modification techniques discussed here depend upon lowering available oxygen for combustion by some form of combustion staging. With proper design and operation, however, no secondary impacts should result for any of the techniques discussed here.

4.3.2 Staged Combustion

The effectiveness of staged combustion in reducing NO_x emissions results from the formation of localized fuel-rich conditions in the primary combustion zone which minimize production of both thermal and fuel NO_x. In fact, stoichiometric conditions in the primary combustion zone typically range from 0.95 to 1.05 for coal-fired boilers. Combustion is completed downstream of the burners. NO_x reduction efficiencies of staged combustion techniques range from 40 to 50 percent when applied to coal units. Efficiencies may be increased by providing additional staging.

One SC technique applied to new and existing boilers is the use of overfire air (OFA). After operating the primary combustion zone under fuel-rich conditions, OFA supplies the air required to complete the combustion process in the secondary combustion zone. NO_x emissions as a function of OFA are presented in Figures 4.3-5 and 4.3-6 for several coal-fired boilers. As noted in each figure, there is a trend toward decreasing NO_x emissions with increasing OFA and a corresponding decrease in primary air.

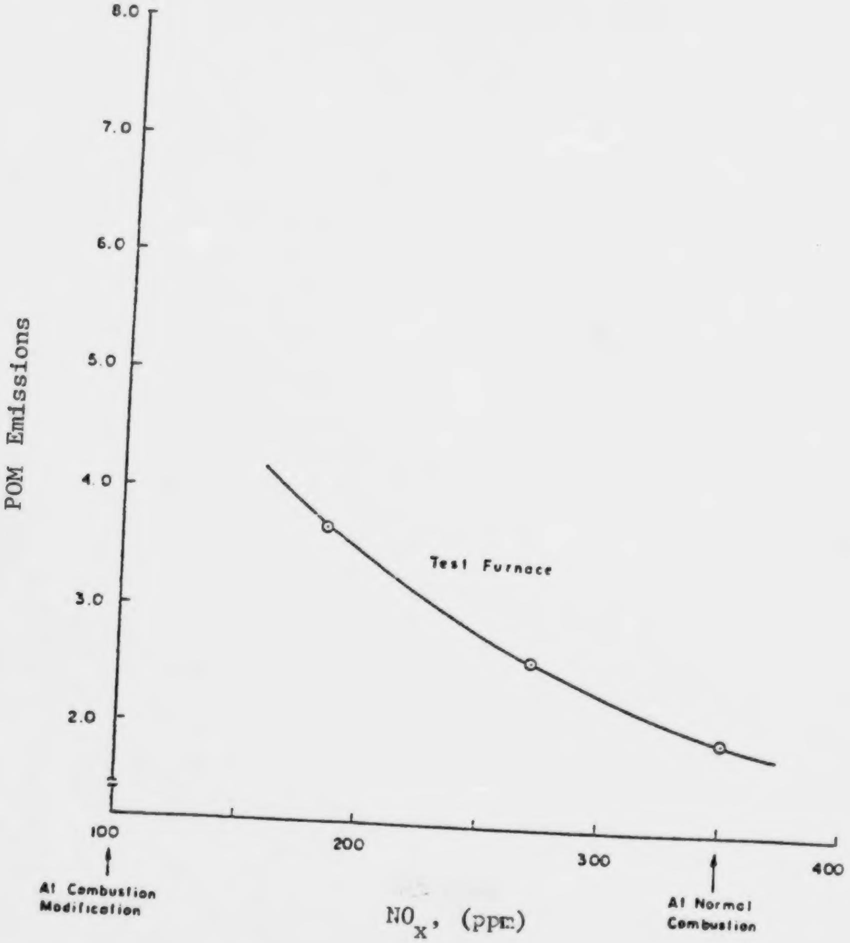
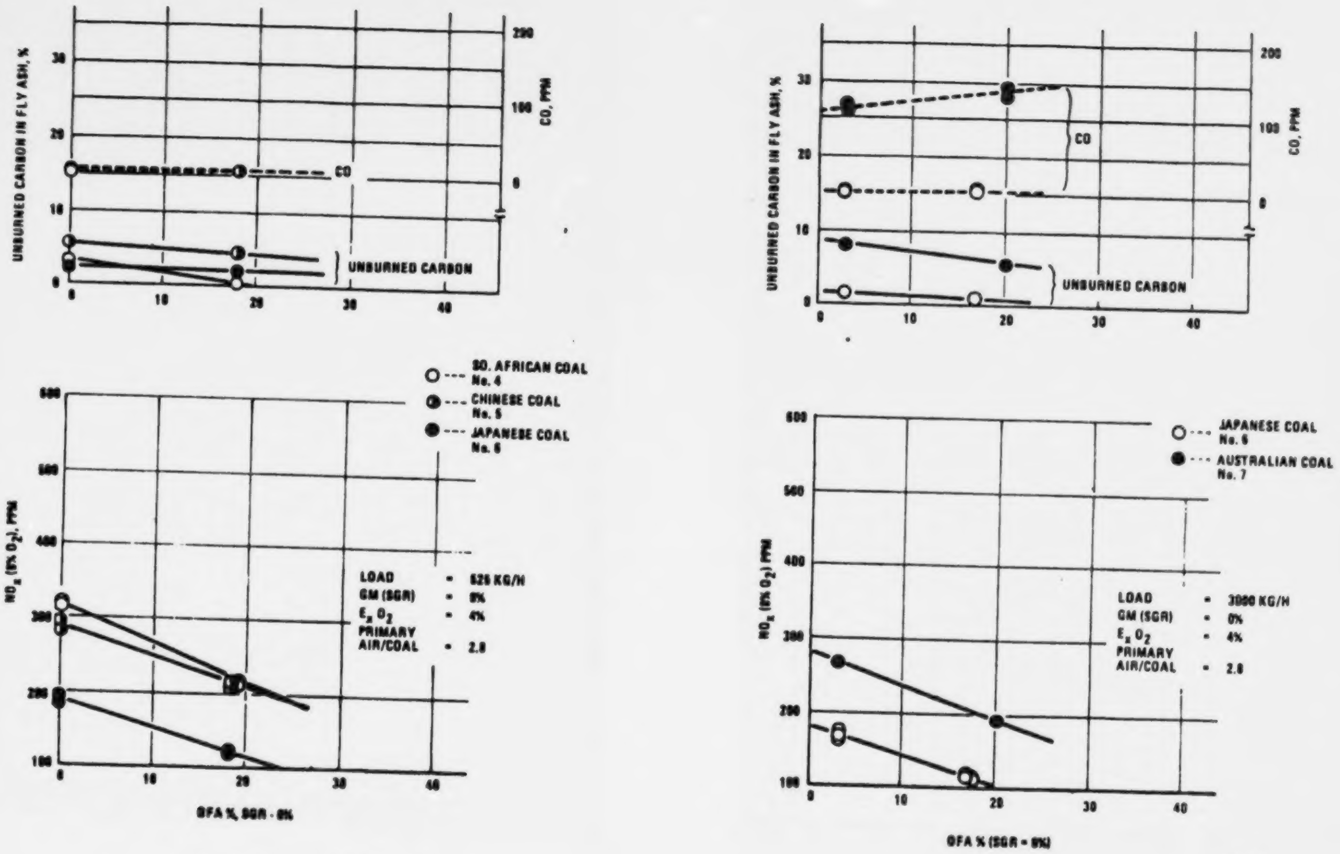


Figure 4.3-4. Correlation of NO_x concentration vs. POM emission.[8]

Note: NO_x concentration of test furnace is the average value of maximum and minimum values.



a. 525 kg/hr (1158 lb/hr)

b. 3,000 kg/hr (6615 lb/hr)

Figure 4.3-5. NO$_x$ emissions as a function of overfire air (OFA) for several coals.[7]
Note: SGR = staged gas recirculation.

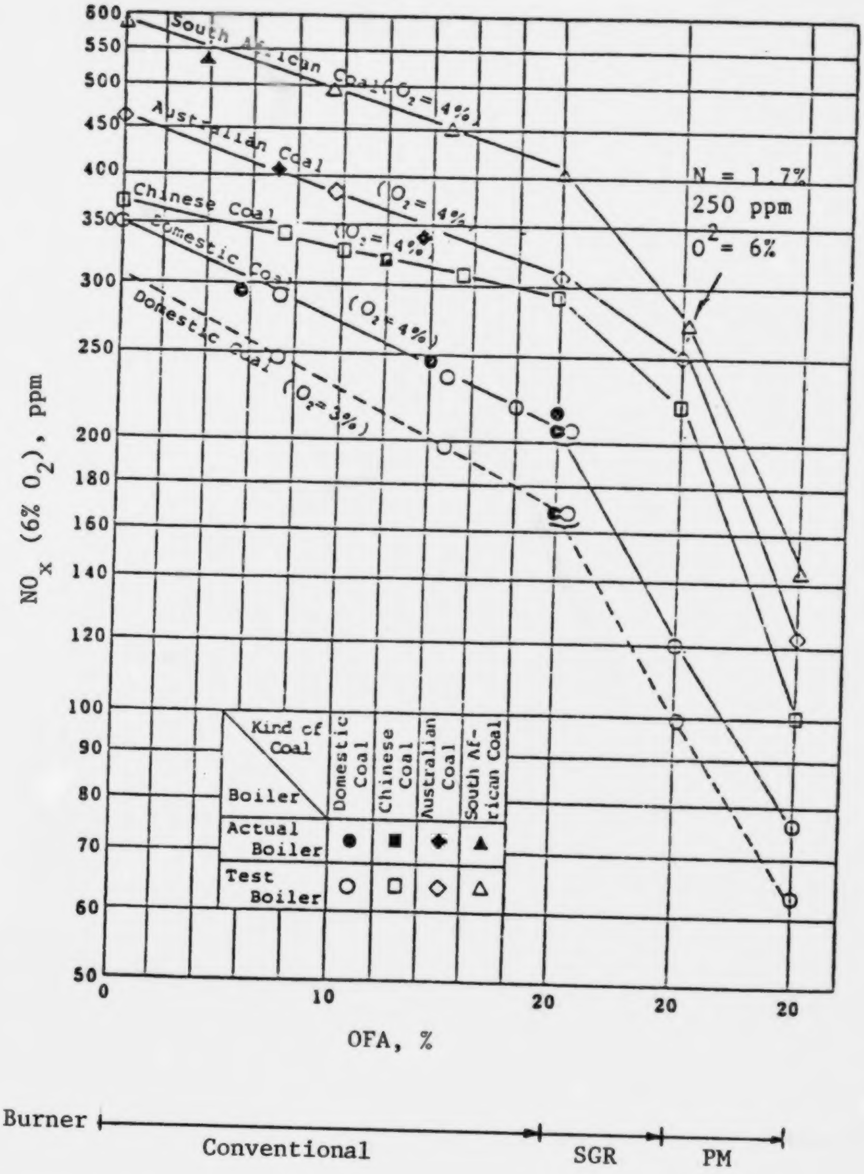


Figure 4.3-6. NO_x emissions with varying OFA for several coals fired in actual and test boilers.[8]

Note: SGR = staged gas recirculation; PM = premixed.

4.3.3 Flue Gas Recirculation (FGR)

Flue gas recirculation is effective in reducing primarily thermal NO_x by lowering the bulk gas temperature of the furnace, and slightly decreasing the concentration of flame oxygen. Since it is primarily effective on thermal NO_x, the use of FGR depends to a great deal on the type of fuel fired. Since coal has a high nitrogen content relative to other fuels, FGR is not a very effective NO_x control technique for coal firing and will likely be ineffective for CWM firing as well.

Figure 4.3-7 indicates the effectiveness of FGR on NO_x emissions from coal-fired boilers. The greatest decrease in NO_x emissions is seen as FGR is increased from 0 to 20 percent. NO_x emissions level off somewhat as FGR is increased beyond 20 percent. FGR is also used in combination with other combustion modification techniques. But as seen for COM combustion in Figure 4.3-8, the dramatic reductions attributable to FGR shown in the previous figure are less evident when combined with staged combustion.

4.3.4 Low-NO_x Burners

Low-NO_x burners achieve substantial NO_x emission reduction by creating combustion conditions at the burner similar to those achieved by the previously discussed combustion modifications. In fact, low-NO_x burner designs typically incorporate one or more of the following techniques: staged combustion, internal FGR, and LEA. By controlling fuel distribution and mixing with combustion air, peak flame temperatures and combustion residence times are reduced, resulting in lower NO_x formation. Low-NO_x burners available for pulverized coal service can potentially reduce uncontrolled NO_x emissions by 65 to 90 percent.

NO_x emissions as a function of the ratio of primary zone air to coal are shown in Figure 4.3-9 for several coals combusted in a low-NO_x burner. As noted in the figure, NO_x emissions are reduced under fuel- rich

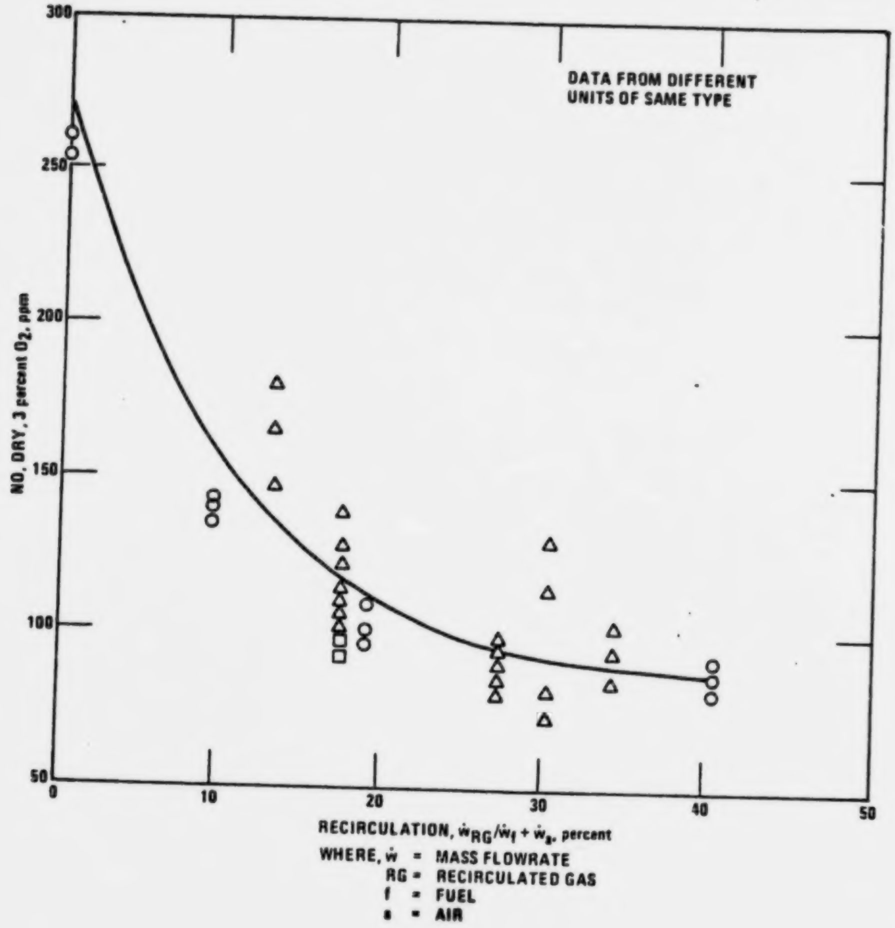


Figure 4.3-7. Effect of FGR on NO emissions.10

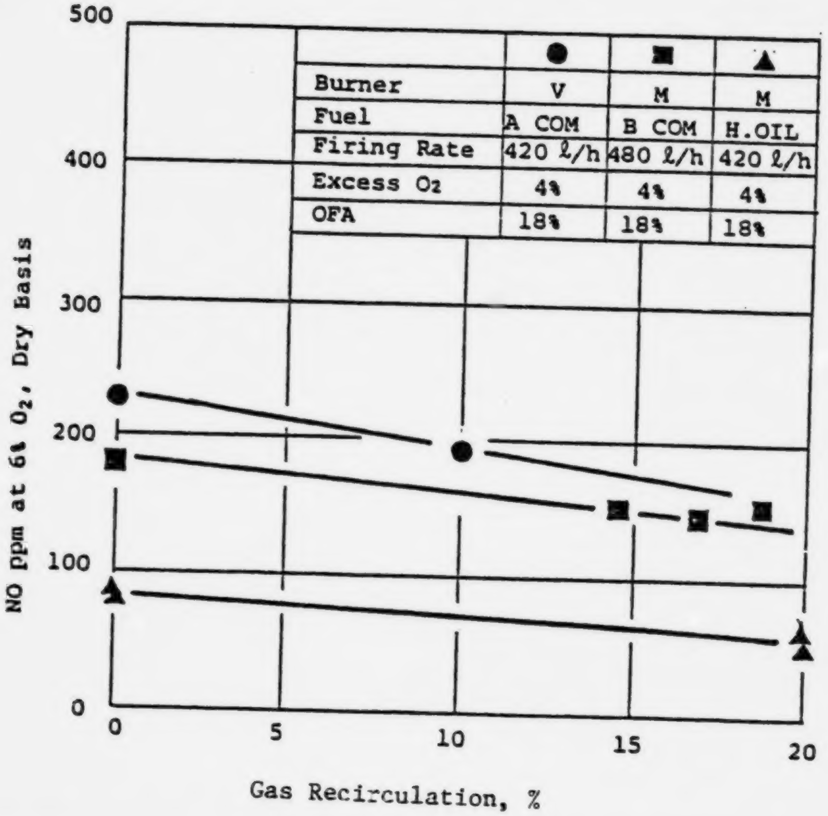


Figure 4.3-8. Combined FGR/staged combustion control of NO_x emissions from COM combustion.[11]

combustion conditions. Low-NO_x burner control of NO_x emissions from COM combustion is shown in Figure 4.3-10. The differences between the various test data shown in this figure are probably due to differing fuel nitrogen contents (both coal and oil nitrogen contents).

Based on these data, low-NO_x burners appear to be the most effective combustion modification technique being developed for reducing NO_x emissions from coal, oil, and COM combustion. It is likely that low-NO_x burners will also be the most effective technique applicable to CWM combustion as well. Furthermore, emissions from CWM combustion are expected to be lower than those shown for coal-only due to reduced flame temperatures associated with CWM combustion.

4.4 POST-COMBUSTION CONTROL TECHNIQUES FOR PM

This section discusses the emission reduction capabilities of two PM control technologies — ESPs and fabric filters. The effectiveness of these technologies is based primarily on the control of fly ash emissions from pulverized coal-firing. Since CWM and coal fly ash should be similar, data from pulverized coal-fired boilers should approximate emissions and performance for CWM-firing. However, there may be some dissimilarities in the characteristics of the fly ash from CWM and coal combustion. These differences might affect the performance of the control systems examined. Thus, they are identified and their effects evaluated. This section also identifies potential secondary environmental impacts resulting from the use of ESPs and fabric filters.

4.4.1 Electrostatic Precipitator (ESP)

4.4.1.1 Pollutant Control Capability--

Electrostatic precipitators can be designed to achieve overall collection efficiencies as high as 99.9 percent. Data from utility and industrial coal-fired boilers indicate that emission levels ranging from

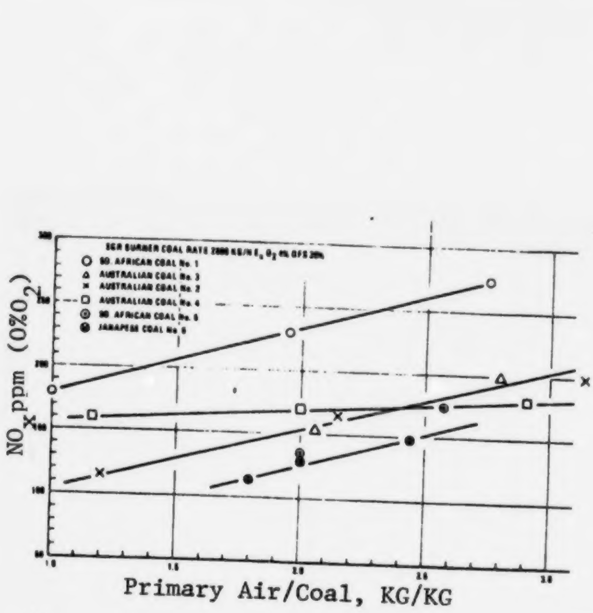


Figure 4.3-9. NO_x emissions as a function of the primary air/coal ratio (fuel rich side) for several coals.[7]

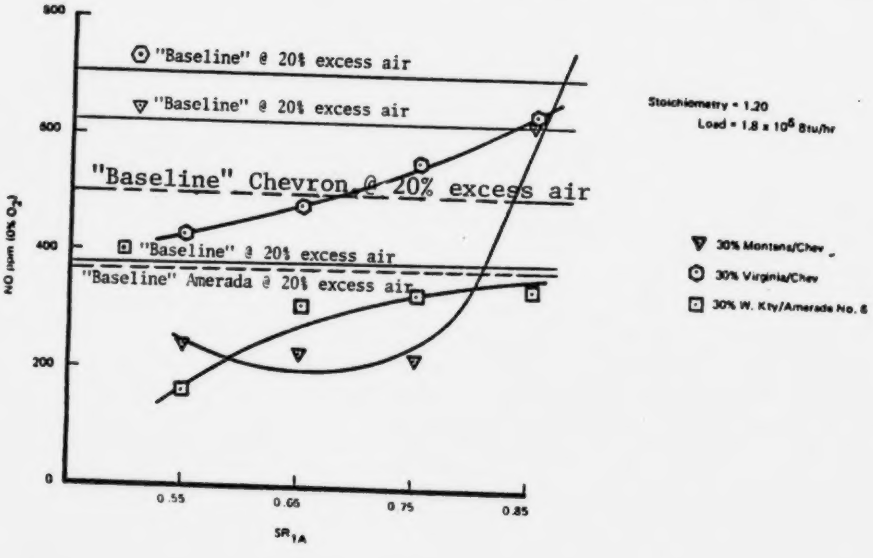


Figure 4.3-10. Low-NO_x burner control of NO_x emissions from COM.[12]

43 ng/J (0.1 lb/10^6 Btu) to 13 ng/J (0.03 lb/10^6 Btu) can be achieved with ESP technology.[13,14,15] In general, however, ESPs with very high collection efficiencies require large specific collection areas and thus are very costly.

ESP collection efficiency varies with fly ash resistivity, particle size distribution, gas velocity distribution, rapping, and electrical factors. Of special significance in CWM applications is the fly ash resistivity, which can be described as the ability to resist collection. Particle resistivity is very sensitive to fuel sulfur content, being altered favorably (lowered) with increasing sulfur content. Consequently, when CWMs are prepared with low-sulfur or cleaned coals instead of high- sulfur coals, ESPs with larger collection areas may be required to attain the desired collection efficiency.

Changes in inlet grain loading (uncontrolled PM emissions) of the flue gas entering the ESP can also have a significant impact on ESP performance. ESPs must be designed for adequate control of the maximum ash content which might occur. If the ash content of the coal used to prepare CWM is widely variable, then the ESP may be unduly overdesigned. Coal cleaning, however, reduces the variability in inlet grain loading by providing a fuel of more uniform ash content. Thus, tighter specifications may be made for the ESP design.

4.4.1.2 Secondary Environmental Impacts--

ESPs used for the collection of fly ash generate a dry solid waste. Disposal of fly ash is generally by landfilling, either at the plant site or in centralized off-site locations. Fly ash from coal-fired boilers is considered "non-hazardous" under current EPA solid waste regulations. Thus, existing state and local regulations, generally formulated under EPA guidelines, will govern the landfill disposal practices. Properly designed and operated landfills present no adverse environmental impacts. Using correct operating procedures, potential leaching and runoff problems can be minimized and the site eventually reused for recreational or building purposes.[16] Alternatives to landfilling include commercial utilization of fly ash in road embankments, concrete mixtures, or sludge stabilization. These alternatives enjoy widespread use in Europe, but their use in the U. S. is still limited.[17]

4.4.2 Fabric Filters

4.4.2.1 Pollutant Control Capability--

Fabric filters generally have PM collection efficiencies of 99.9+ percent and are widely considered the most effective PM control technology for coal-fired boilers. Results of tests conducted on several coal- fired industrial boilers using fabric filters showed that, in nearly every case, the fabric filters reduced PM emissions to less than 43 ng/J (0.10 lb/10^6 Btu). In 50 percent of the cases, PM emissions were less than 13 ng/J (0.03 lb/10^6 Btu).[18] Likewise, fabric filters applied to utility boilers have achieved similar results.[19] Although several utility boilers are equipped with fabric filters, their use is more widespread for industrial boilers.

Based on their performance on coal-fired boilers, fabric filters are expected to be equally as effective when applied to boilers firing CWMs. Fabric filters are attractive for CWM combustion because their performance is generally unaffected by changes in inlet grain loading, particle size distribution, and particle resistivity. Special care must be taken during start-up and shutdown to avoid condensation in the baghouse that could lead to bag blinding. And, if multifuel-firing capability is desired, fabric filters may not be the best choice. Oil- firing produces fly ash which can cause bag blinding; so fabric filters are rarely used on oil-fired boilers. At least one COM facility has installed fabric filters for PM control and, with careful operating practices, anticipates minimal problems.[20]

Sulfur and water content of the CWM are important design considerations because they are potentially corrosive at temperatures below the acid dewpoint. Operating temperatures are most likely to fall below the acid dewpoint during start-up, shutdown, or periods of fluctuating load. Corrosion problems can be minimized by proper fabric/material selection and by using cleaned fuels.

4.4.2.2 Secondary Environmental Impacts--

The solid waste impacts associated with fabric filters are basically the same as those discussed for ESPs in Section 4.4.1.2. But, depending upon the PM removal efficiency of an ESP as compared to a fabric filter, there may be an incrementally greater amount of fly ash collected with a fabric filter. For example, consider a fabric filter with a PM emission control level of 21 ng/J (0.05 $lb/10^6$ Btu) and an ESP with PM emission control of 43 ng/J (0.10 $lb/10^6$ Btu). The difference in collected fly ash could amount to an additional 3175 Mg/yr (3500 ton/yr) of fly ash disposal for a 205 MW_t (700 x 10^6 Btu/hr) boiler, with a 60 percent annual capacity factor, firing a CWM with uncontrolled PM emissions of 860 ng/J (2.0 $lb/10^6$ Btu).

4.5 POST-COMBUSTION CONTROL TECHNIQUES FOR PM/SO_2

This section presents the environmental impacts associated with technologies used in controlling both PM and SO_2 emissions:

- wet flue gas desulfurization (wet FGD), and
- dry flue gas desulfurization (dry FGD).

These control technologies are used primarily for SO_2 control but achieve moderate to substantial reductions in PM emissions also. The control capability and secondary environmental impacts associated with each of these technologies are discussed below.

4.5.1 Wet Flue Gas Desulfurization (Wet FGD)

The wet FGD techniques most applicable to coal- and CWM-fired boilers include dual alkali, lime/limestone, and sodium throwaway. Although the pollutant control capabilities of these three techniques are similar, the secondary environmental impacts associated with each may differ. For example, dual alkali and lime/limestone systems have similar solid and liquid waste impacts. But the liquid waste impacts of the sodium throwaway systems are potentially more serious.

4.5.1.1 Pollutant Control Capability--

Wet FGD systems can achieve 90 percent removal of SO_2 or greater if they are designed and maintained properly.[21] Figure 4.5-1 shows the annual SO_2 emission (as a function of boiler size) for different sulfur content CWMs, assuming 90 percent SO_2 removal. As noted in the figure, the annual SO_2 emissions can be substantial, even at SO_2 removal efficiencies of 90 percent. Figure 4.5-2 presents SO_2 emissions per unit heat input as a function of the percent sulfur removed for various CWM sulfur contents. Uncontrolled SO_2 emissions from high and low sulfur fuel oils, and current NSPS for utility and industrial coal-fired boilers are shown for comparison. As indicated in the figure, a 0.5 percent sulfur CWM would result in uncontrolled SO_2 emissions of 520 ng/J (1.2 lb/10^6 Btu). A 1.0 percent sulfur CWM requires 40 percent removal to meet this emissions level. A 2.0 percent sulfur CWM requires 70 percent removal, and a 2.5 percent sulfur CWM requires about 80 percent removal.

Wet FGD systems can achieve high SO_2 removal efficiencies for most inlet SO_2 concentrations. Various FGD systems have been used to treat flue gas with inlet SO_2 concentrations as low as 150 ppm or as high as 3800 ppm.[22] High efficiencies at low inlet SO_2 concentrations are necessary for the treatment of flue gas from combustion of CWMs with low sulfur content.

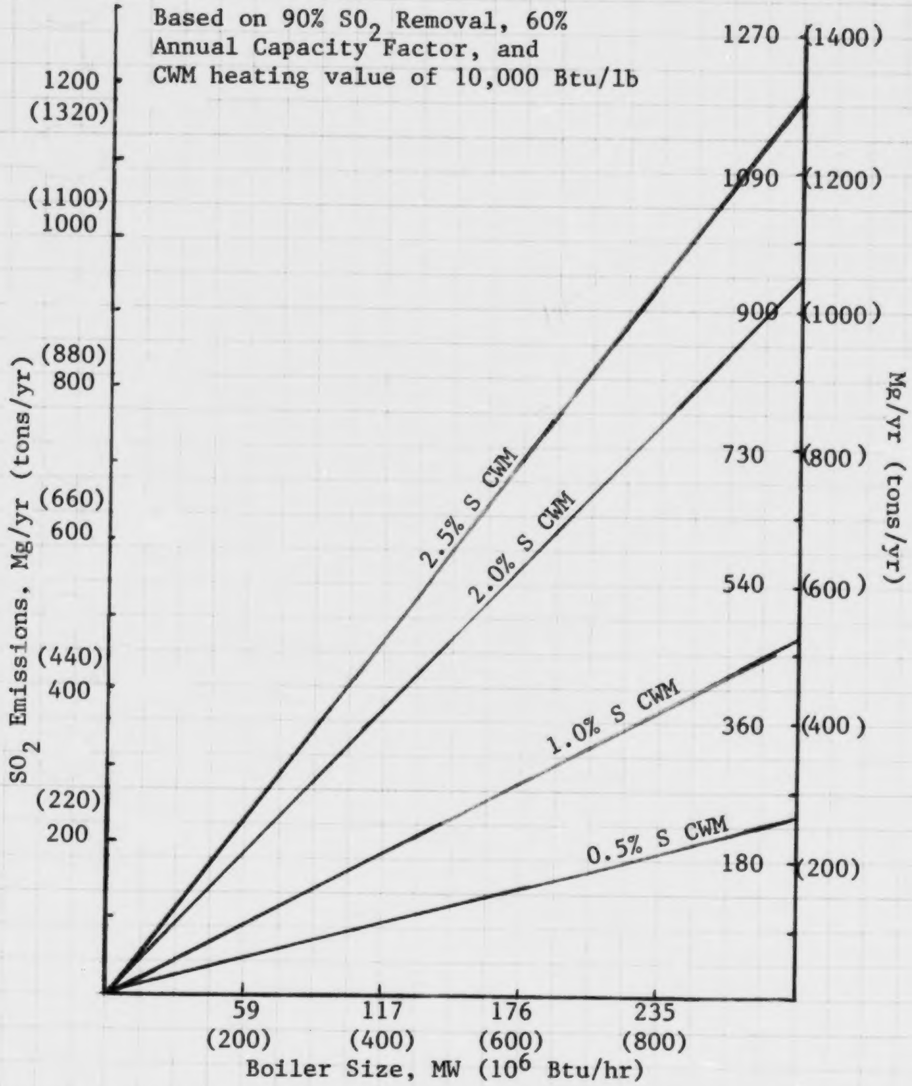


Figure 4.5-1. Annual SO_2 emissions for various CWM sulfur contents as a function of boiler size.

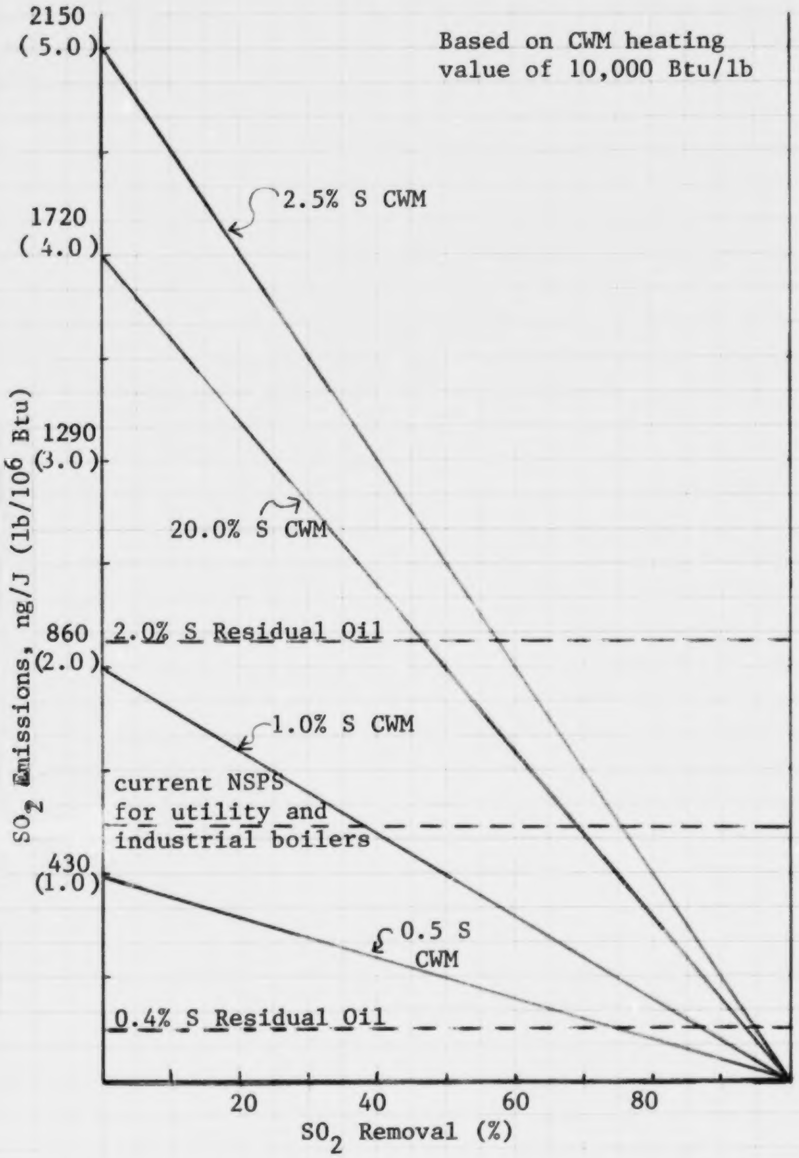


Figure 4.5-2. SO_2 emissions vs. percent removal for various CWM sulfur contents.

Because FGD systems are designed for constant removal efficiencies rather than constant outlet concentration, wide fluctuations in inlet SO_2 concentration create operating problems. Boilers subject to stringent SO_2 regulations will require FGD systems to be liberally overdesigned, often resulting in an overly expensive control system. Coal cleaning processes reduce the variability in CWM sulfur content, thus minimizing fluctuation in SO_2 concentrations to be treated and allowing tighter, more cost effective FGD design.

As discussed in Section 3.6.2.4, wet FGD systems are often effective in removing PM in addition to SO_2. Venturi scrubbers are most often used in FGD applications where dual removal capability is desired. Particulate matter emissions have been reduced to less than 43 ng/J (0.1 $lb/10^6$ Btu) in various FGD systems. For wet scrubbers, the PM removal efficiency attained is related to the pressure drop across the scrubber. This relationship is shown in Figure 4.5-3. Many PM/SO_2 scrubber systems utilize a mechanical collector upstream of the FGD unit to collect large fly ash particles, reducing the inlet PM loading to the FGD system. Several potential problems occur if excessive amounts of fly ash are introduced into the FGD system. These problems include plugging of the demister, difficulty in controlling the liquor flowrate to the absorber, and erosion of scrubber internals.[24]

Some wet FGD systems are not designed for combined PM/SO_2 removal. In these cases, some other type of upstream PM control will be required to assure reliable FGD operation.

4.5.1.2 Secondary Environmental Impacts--

The secondary environmental impacts associated with the use of wet FGD systems include:

- reduced pollutant dispersion due to poor plume buoyancy,
- production of sludge waste for disposal, and
- potential water pollution impacts.

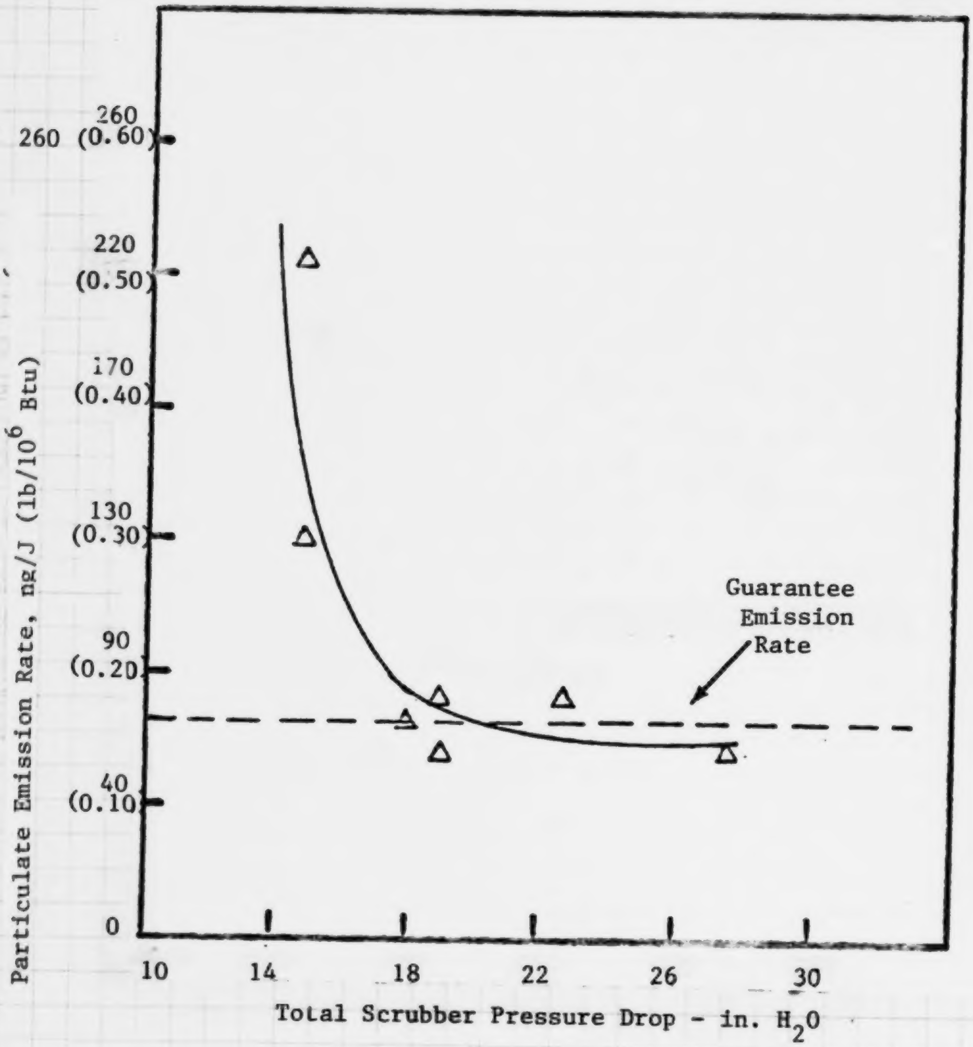


Figure 4.5-3. The effect of scrubber pressure drop on particulate emission rates.[23]

Proper pollutant dispersion is needed to reduce ground-level pollutant concentrations to acceptable limits. Saturation of the waste gas stream can have an adverse impact on plume buoyancy, resulting in decreased pollutant dispersion. This reduced pollutant dispersion due to poor plume buoyancy can be alleviated by using stack gas reheat. A detailed discussion of reheat requirements and methods is presented by Menzies, et al., in "Stack Gas Reheat Evaluation."

Lime, limestone, and dual alkali wet FGD systems produce sludge waste containing about 35 to 60 percent solids. These sludges consist primarily of calcium sulfite, sulfate salts, and fly ash. Disposal of the sludges is generally by ponding or landfilling. The potential adverse impacts of sludge disposal lie in the areas of disposal acreage requirements and water contamination through leaching and percolation of soluble components of the solid waste into the groundwater system. The treatment techniques used to minimize these adverse impacts may involve dewatering, addition of alkaline ash, and application of commercial stabilization technology. These techniques are used to decrease the sludge volume, decrease its permeability and improve its structural properties.[25] Figure 4.5-4 shows the annual sludge production rates for a dual alkali FGD system (operating at 90 percent SO_2 removal) as a function of boiler size for four different sulfur content CWMs. The rates are based on a 60 percent annual operating capacity and a 60 weight percent solids waste. Ash disposal is not included in these estimates. Ash disposal estimates are presented in Figure 4.5-5. This figure indicates that ash disposal rates are substantially higher than sludge disposal rates due to SO_2 removal alone. The effect of ash disposal is especially significant for high-ash CWMs.

Dual alkali and lime/limestone systems can be designed on a closed-loop basis so that the only water losses during normal operation are those which accompany the sludge going to landfill.[26] The water pollution impacts associated with sodium throwaway systems are more severe than those for lime/limestone and dual alkali. Sodium throwaway FGD systems produce an

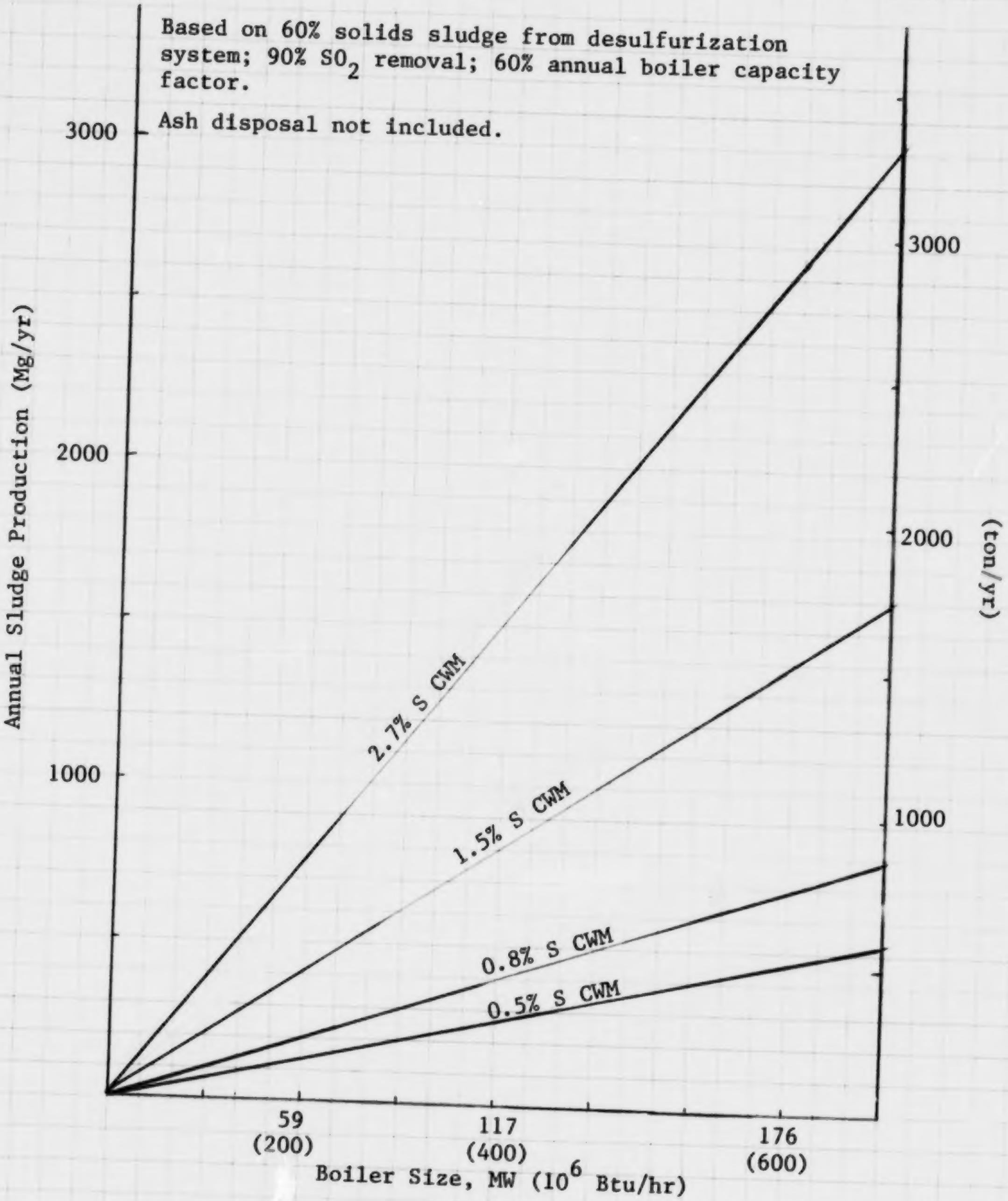
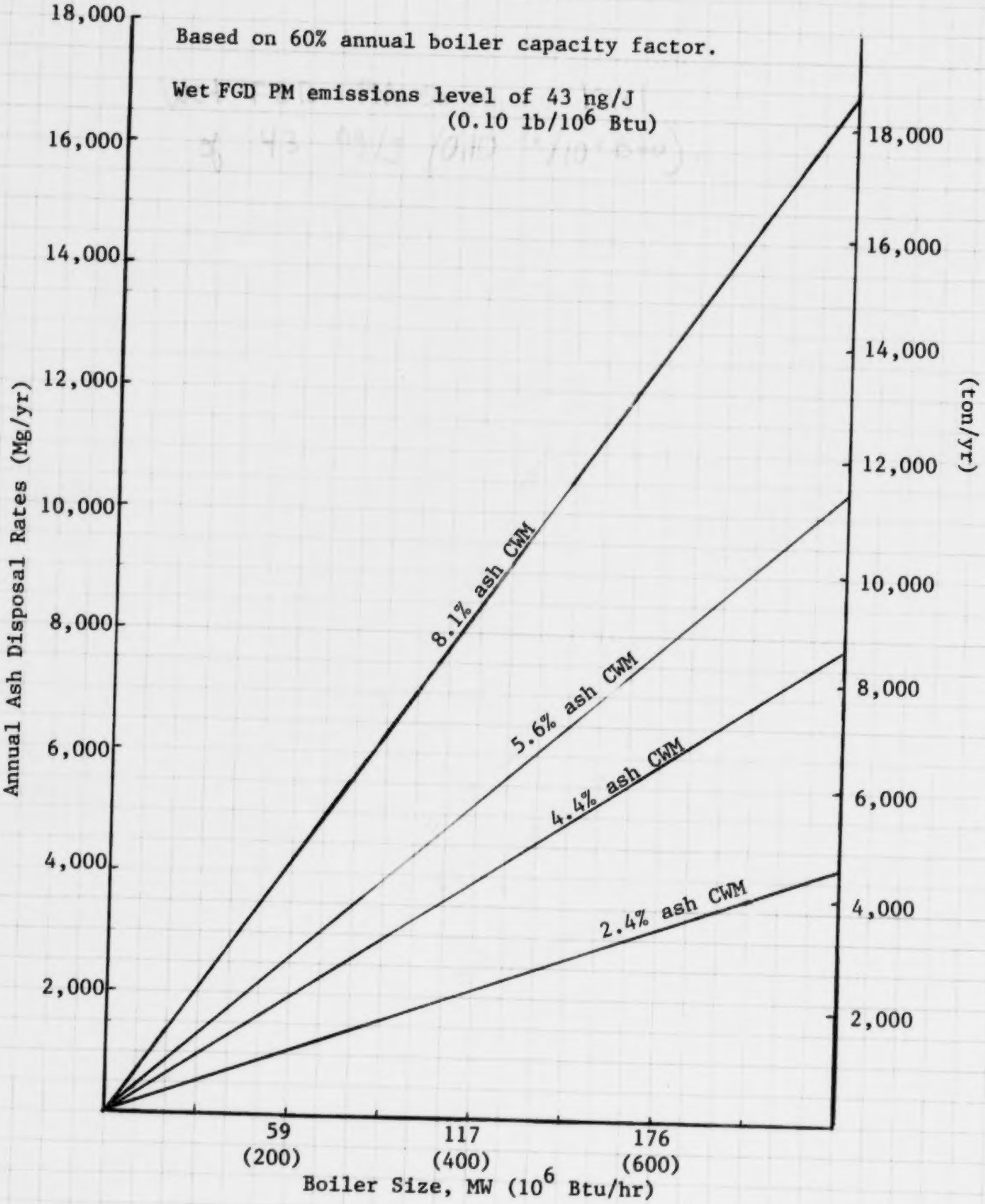


Figure 4.5-4. Annual sludge production for 90% SO_2 removal as a function of boiler size for different sulfur content CWMs.



Based on 60% annual boiler capacity factor.

Wet FGD PM emissions level of 43 ng/J (0.10 lb/10^6 Btu)

Figure 4.5-5. Annual ash disposal rates for wet FGD as a function of boiler size for various ash content CWMs.

aqueous waste containing about 5 percent dissolved sodium sulfate, sodium sulfite, and sulfate salts. This aqueous waste is generally discharged to an evaporation pond or to an existing centralized wastewater treatment facility. The use of evaporation ponds is limited to those geographical locations where the annual evaporation rate exceeds the annual rainfall. Waste water treatment generally involves sulfite oxidation and pH neutralization.[27]

4.5.2 Dry Flue Gas Desulfurization (Dry FGD)

4.5.2.1 Pollutant Control Capability--

There are two types of dry FGD systems which appear to be promising for CWM applications — spray drying FGD and dry injection of sodium- based compounds. Spray dryers are being used commercially but dry- injection has not progressed past the demonstration stage.

As of the end of 1981, twelve utility and twelve industrial spray drying systems had been sold.[28] However, only three of these systems (all industrial) are currently operational. Another industrial system is in the final stages of start-up and two others are due to start-up later in 1982.[29] In addition, there are two utility spray drying systems in the demonstration stages.[29]

Although spray dryers were initially used only on units firing low-sulfur coals, their use has expanded to include high-sulfur coals. Spray drying SO_2 removal efficiencies of up to 92 percent have been reported for industrial and utility units firing both low-sulfur and high-sulfur coals.[28,30,31]

Dry injection of sodium-based compounds (such as trona, nahcolite, and sodium bicarbonate) into SO_2-laden flue gas passing through a fabric filter has shown substantial SO_2 removal potential. Nahcolite, a naturally occurring mineral which contains about 80 percent sodium bicarbonate, has been used as the sorbent in most programs. Sodium bicarbonate injected into the flue gas stream reacts with SO_2 to form sodium salts. It appears that a significant portion of the SO_2 removal reaction occurs on the fabric filter surface. The fabric filter serves as a collection device for both the sodium salts and fly ash.

Although no full-scale commercial systems are in operation, dry-injection has demonstrated SO_2 removal efficiencies of 60 to 90 percent in pilot-scale tests.[28] Dry injection was used in DOE tests of the COM pilot facility located at the Pittsburgh Energy Technology Center. Up to 90 percent SO_2 removal was obtained during firing of a low-sulfur COM (1 percent sulfur).[32]

Both spray drying and dry injection achieve significant PM control since fabric filters are included in the systems. ESPs are seldom used on spray drying systems, even though they could be applied. The primary advantage of fabric filters over ESPs is that unreacted alkalinity in the solids collected on the bag surface can react with SO_2 in the flue gas. One potential advantage of ESPs over baghouses in spray drying applications is that ESPs are less sensitive to condensation. The spray dryer can therefore be operated closer to the saturation temperature, resulting in higher SO_2 removals across the spray dryer.[33] PM removal efficiencies of fabric filters and ESPs are discussed in Section 4.4.

4.5.2.2 Secondary Environmental Impacts--

The secondary environmental impacts of spray drying FGD are similar to those of wet FGD. The potential impacts of dry injection, however, are more severe than those of wet FGD.

Impacts associated with spray drying are (1) reduced plume buoyancy due to cooling of the flue gas and (2) production of solid waste for disposal. Spray drying cools the flue gases to within 11 to 28°C (52 to 82°F) of its adiabatic saturation temperature. The problem of reduced plume buoyancy is not as great as with wet FGD and can be avoided by using gas reheat. The solid waste generated in a lime spray drying system is a mixture of calcium compounds and fly ash, generally having a moisture content of less than 5 percent. Solid wastes from dry scrubbing can be disposed of in the same manner as wet FGD solid wastes. Commercial utilization of dry scrubbing waste solids as a road-base or cement additive is also being investigated.[28]

The environmental impacts of solid waste generated by sodium-based dry injection are potentially severe if improperly handled. Dry injection generates highly leachable sodium salts which could result in groundwater contamination. An acceptable means of disposal may be a clay-lined landfill, provided the wastes are encapsulated in cells with clay-lined top, bottom and sides. Clay liners which might be susceptible to breakdown or swelling under high-sodium conditions must be avoided.

4.6 POST-COMBUSTION TECHNIQUES FOR NO_X CONTROL

There are a number of flue gas treatment (FGT) processes available for reducing NO_x in combustion flue gases. They have not been applied widely to sources in the United States since existing emission limits can be met by fuel switching (low-nitrogen fuels such as natural gas) or by combustion modifications as discussed in Section 4.3. But NO_x FGT is well developed in Japan where NO_x emission limits are more stringent.

NO_x FGT processes can be classified as either dry or wet processes. The major wet FGT processes include absorption-reduction, absorption-oxidation, and oxidation-absorption. These processes represent only about 12 percent of the FGT systems in use in the United States and Japan today, however. They may be limited to flue gases with high SO_x:NO_x ratios since up to 95 percent SO_x reduction is achievable and only about 90 percent NO_x removal is expected.

Of the major dry FGT processes for NO_x removal, selective catalytic reduction (SCR) and selective non-catalytic reduction with ammonia are the most widely used, accounting for about 64 and 23 percent, respectively, of all NO_x FGT systems in use in the United States and Japan. And SCR has been used in at least 4 utility applications in the United States. Vendors of SCR units guarantee reductions of NO_x emissions of from 80 to 95 percent, with the general concensus being that systems installed on utility boilers can routinely achieve 80 percent or better reduction efficiencies. The 80 percent reduction by FGT is the basis of the proposed emission limits for coal-fired power plants in California.

NO_x removal efficiency is presented as a function of NH_3/NO_x mole ratio for two SCR processes in Figures 4.6-1 and 4.6-2. In both cases, as the mole ratio increases to unity and above, the removal efficiency also increases. Based on the data presented in these figures, efficiencies of 90 percent are achievable with an ammonia slip (unreacted ammonia) of 10 to 20 ppm.

The secondary impacts associated with NO_x FGT techniques are primarily emissions of unreacted ammonia. As the NH_3/NO_x mole ratio is increased to increase the reduction efficiency, the unreacted ammonia or ammonia slip increases. Another secondary impact would be the additional fan power required to account for the pressure drop across the FGT system.

4.7 TRACE ELEMENT CONTROL

This section examines the trace element control capability of the various particulate matter, SO_2, and NO_x control technologies discussed in previous sections. No data are available which indicate the capabilities of the various technologies to reduce trace elements from CWM combustion. This discussion is based on test data from coal combustion or, in the absence of data, on the operational characteristics of the emission control system.

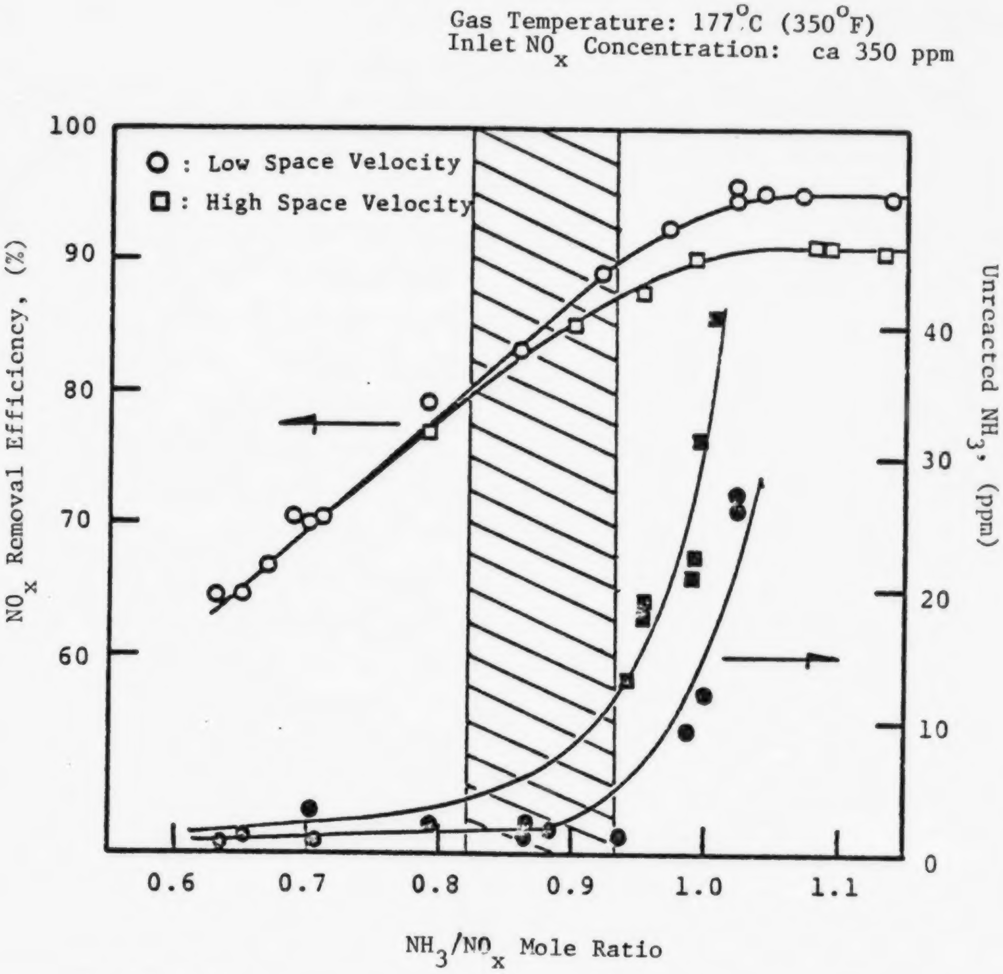


Figure 4.6-1. Control region of NH_3/NO_x mole ratio for Kawasaki Heavy Industries' $DeNO_x$ system.[34]

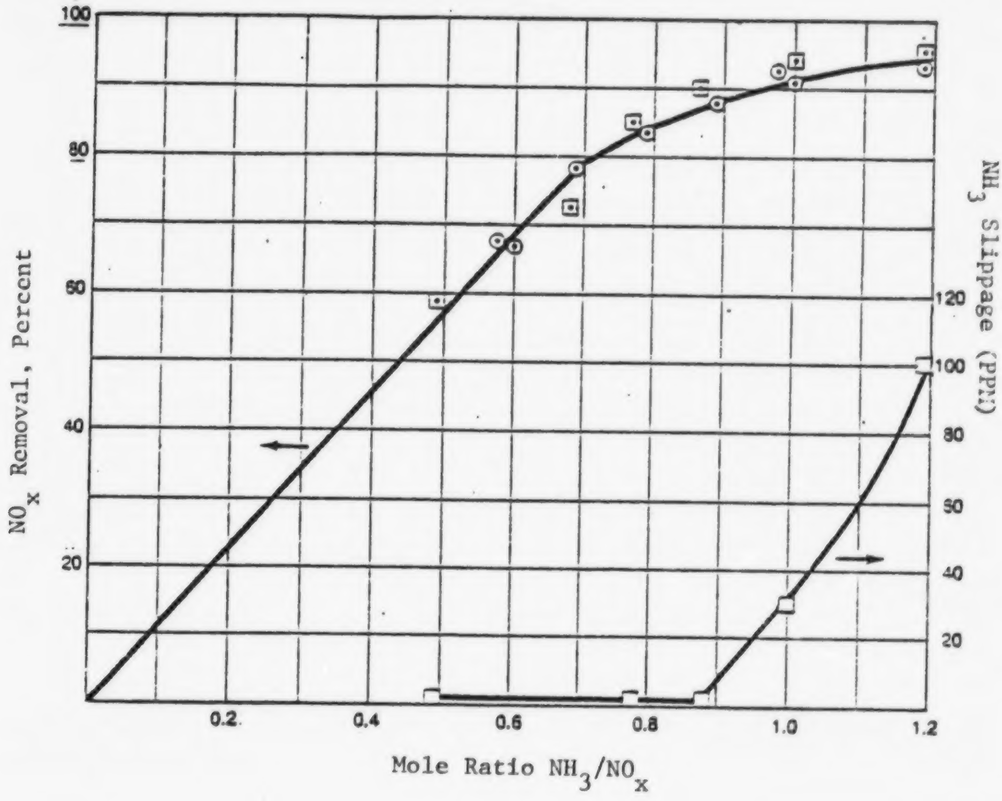


Figure 4.6-2. NO_x removal for the Hitachi Zosen NO_x removal system operated between 371 and 377°C (700 and 710°F) with inlet NO_x concentration of 400-500 ppm.[35]

Physical coal cleaning should be an effective means of reducing trace elements in emissions by removing trace elements from the coals used to prepare CWMs. Combustion modification techniques (such as LEA, staged combustion, FGR, or low-NO_x burners) which alter the oxygen concentration or temperature in the flame zone may affect the oxidation of volatile trace element compounds. However, the effects of these techniques on trace element emissions have not been documented due to insufficient data. Most trace elements tend to be enriched on small fly ash particles and their collection is best accomplished by high efficiency PM technologies such as fabric filters, ESPs, and wet scrubbers. Mercury (Hg) and selenium (Se) tend to remain, completely or in part, in the vapor phase. Those techniques which cool the flue gas stream (wet scrubbers, FGD systems) are the most efficient collection techniques for these trace elements.

In terms of the secondary effects of pollutant control, trace elements removed by the various PM, SO_2, and NO_x control technologies would then be associated with the liquid or solid waste generated by the technologies.

4.7.1 Impact of Pre-Combustion Controls on Trace Element Emissions

Physical coal cleaning techniques will remove significant quantities of trace elements from the coal. Physical coal cleaning (PCC) should be most effective in removing arsenic (As), cadmium (Cd), mercury (Hg), and manganese (Mn), since these elements tend to be associated with the inorganic constituents of coal which are removed by PCC. (See Section 4.2.1 for discussion of PCC's effect on inorganic and organic constituents of coal.) Chromium (Cr), nickel (Ni), vanadium (V), and selenium (Se) are associated with both the organic and inorganic portions, so that they will be removed to some extent by PCC. Beryllium (Be) is associated with the organic portion of coal so that PCC will not be an effective means of removal.[36]

Table 4.7-1 presents removal efficiencies of a few trace elements for "float-sink" coal washing. (As discussed in Section 4.2, undesired ash, pyritic sulfur, and other mineral matter are denser than coal. These "undesirables" can then be removed from ground coal using gravity separation techniques — the product floats, and the refuse sinks.)

More extensive data on the effect of physical coal cleaning are presented in Table 4.7-2. Twenty run-of-mine (ROM) coal samples obtained from various geographical locations were subjected to controlled coal cleaning. These removal efficiencies were calculated by comparing the mass of trace element per heating value for the cleaned coal to that for the feed coal. Since the cleaning affects the heating value of the coal, these values more closely reflect the control of trace element emissions from burning the coal than a comparison of the mass of trace elements in the cleaned and feed coals. The average removal efficiencies for all 20 coals are presented in Table 4.7-2, along with the averages for the Eastern, Midwestern, and Western coals. As shown, the Eastern and Midwestern coals were generally cleaned more effectively than the Western coals, possibly because the Western coals have a lower initial concentration of impurities. On the average, arsenic (As) and manganese (Mn) were removed most effectively (60 percent), followed by cadmium (Cd) and chromium (Cr) (50 percent), and nickel (Ni), selenium (Se), mercury (Hg), and vanadium (V) (40 percent). Beryllium (Be) was removed least effectively (32 percent).

4.7.2 Impact of Post-Combustion Controls on Trace Element Emissions

4.7.2.1 PM Controls--

Fabric filters and ESPs, designed for high efficiency removal of fine PM, have been the most effective trace element controls. The collection efficiencies of these two techniques are shown in Tables 4.7-3 and 4.7-4. These data show that fabric filters achieve over 99 percent collection of all trace elements except mercury and selenium.

TABLE 4.7-1. REDUCTION OF TRACE ELEMENTS IN COAL BY FLOAT-SINK WASHING

	Source A			Source B	
Element	Reduction (%)	Concentration Remaining in coal (ppm)	No. Samples	Reduction (%)	No. Samples
Cd	0-97	0.02-0.10	3	0	1
Cr	28-60	10-20	2	29-56	2
Hg	47	0.17	1	24-47	3
Mn	50-78	7-68	2	50-75	2
Ni	20-27	11-27	2	28-30	2

TABLE 4.7-2. COMPARISON BY REGION OF REMOVAL EFFICIENCY FOR TRACE ELEMENTS BY PHYSICAL COAL CLEANING

Element	Average%, 20 coals	Average%, East	Average%, Midwest	Average, West
As	62.5	69.2	57.5	49.3
Be	32.4	43.0	28.0	9.87
Cd	51.9	49.5	73.8	44.7
Cr	53.4	65.2	49.8	27.3
Mn	65.1	79.1	72.8	26.7
Hg	41.1	52.2	25.6	24.0
Ni	40.6	49.7	50.7	12.5
Se	40.6	48.2	32.4	27.3
V	45.1	61.6	36.5	10.5
Ash	56	69	55	27

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[a] Ash removal efficiency based on mass; trace element removals based on mass per heating value. Negative removal efficiencies were assumed to be zero in calculating averages.

TABLE 4.7-3. TRACE ELEMENT COLLECTION EFFICIENCIES FOR FABRIC FILTERS[a]

	Collection Efficiency, %	
Element	Method5[b]	Impactor[c]
As	99.94	99.94
Be	NR[d]	NR
Cd	NR	NR
Cr[e]	99.70	99.94
Hg[e]	67.14	99.77
Mn	99.94	99.78
Ni[e]	99.51	99.71
Se[e]	93.41	99.40
V	99.95	99.77
Ash	99.63	99.68

[a] This plant is a pulverized coalfired utility boiler fired with 0.3% S subbituminous coal. Samples analyzed by NAA. (Test program sponsored by EPRI.)

[b] Samples collected by EPA Method 5.

[c] Samples collected by low pressure impactor.

[d] NR Not Reported.

[e] Volatile elements. Method 5 collection efficiencies include volatile fraction collected in impingers. Impactor values do not. Collection of volatile fraction not considered adequate.

TABLE 4.7-4. TRACE ELEMENT COLLECTION EFFICIENCIES FOR ELECTROSTATIC PRECIPITATORS AT COALFIRED POWER PLANTS[37]

Trace Element	Collection Efficiency, %				
	Plant A[a]	Plant B[b]	Plant C[c]	Plant D[d,e]	Plant E[d,f]
As	98.4	97.5	NR	99.3	97.0
Be	NR	NR	NR	NR	99.0
Cd	NR	99.6	99.8	63	93
Cr	99.8	98.6	99.8	98.7	97.0
Hg	60.0	42.5	NR	NM	23.0
Mn	94.2	99.1	100	94.4	66.0
Ni	96.3	99.4	99.7	99.8	98.0
Se	97.2	82.895.7[g]	94.3	NR	NR
V	95.9	98.8	99.9	99.3	94.0
Ash	99.3	99.5	99.7	99.7	97.5

FOOTNOTES FOR TABLE 4.7-4

NR = Not Reported: NM Negative Removal; outlet measured value greater than inlet.

[a] Plant A is a pulverized coalfired utility boiler fired with low S subbituminous coal. Samples collected by Method 5, analyzed by neutron activation analysis (NAA). (Test program sponsored by EPRI.)

[b] Plant B is a cyclone utility boiler fired with 3.4% bituminous coal. Samples collected by sampling train similar to EPA Method 5 (multipoint sampling), and analyzed by NAA except Cd by Isotope Dilution Spark Source Mass Spectrometry, Hg by atomic absorption (AA), Ni by Xray fluorescence; one run for Se by gas chromatography microwave emission spectroscopy. (Study performed by Oak Ridge National Laboratory.)

[c] Plant C is a utility boiler; boiler and coal type not specified. Samples collected by in stack cascade impactor, analyzed by flameless AA except Se by NAA. (EPA Study.)

[d] Samples collected by SASS train at a single point in the ducts, analyzed by inductively coupled plasma optical emission spectroscopy (ICP) except As by AA and Hg by cold water.

[e] Pulverized coalfired dry bottom utility boiler fired with Eastern bituminous coal, 3.56.3% S.

[f] Pulverized coalfired dry bottom utility boiler fired with 3.2% S high volatile bituminous coal.

[g] Different values are for 2 different analytical techniques. (Measured both inlet and outlet for these data.)

ESPs also show a high degree of trace element control achieving greater than 95 percent removal of trace elements except mercury and selenium. Removal efficiencies were much lower for mercury and selenium since these elements are emitted as solids and vapors.

4.7.2.2 PM/SO_2 Controls--

The only data available concerning the trace element control capabilities of combined PM/SO_2 control techniques, applied to coal-fired boilers, is for dual alkali venturi scrubber FGD systems. Table 4.7-5 shows measured trace element collection efficiencies for a dual alkali/venturi scrubber and Table 4.7-6 shows efficiencies for a dual alkali scrubber preceded by an ESP. The dual alkali scrubber system achieved collection efficiencies ranging from 55 percent for mercury to 99 percent for cadmium. The dual alkali FGD system preceded by an ESP achieved a 97 percent removal of mercury. The removal efficiencies of the other trace elements shown in Table 4.7-6 appear to be low, but this is due to the high degree of collection achieved in the ESP.

Although no trace element collection data are available for the other wet FGD systems, their performance is expected to be similar to that of the dual alkali system.

Spray drying and dry injection of sodium-based compounds will achieve substantial trace element removal since these systems include fabric filters.

A reduction of trace elements in the flue gases, using the techniques described above, naturally results in an increase in trace element concentration in the liquid and solid waste streams. The major problem associated with trace elements in liquid and solid waste streams is leaching. This problem can be minimized through proper design and operation of disposal facilities.

TABLE 4.7-5. TRACE ELEMENT COLLECTION EFFICIENCY FOR A COMBINED DUAL ALKALI/VENTURI SCRUBBER SYSTEM

Element	Trace Element Collection Efficiency, % Plant LC[a]	 Plant LO[a]
As	97	81
Be	98	NM[b]
Cd	99	77
Cr	95	90
Hg	55	87
Mn	98	87
Ni	95	83
Se	97	87
V	98	71
Ash	99.4	7584

[a] Industrial boiler capable of firing pulverized coal or No. 6 fuel oil. Plant LC fired with coal; Plant LO fired with oil. Samples collected by SASS train, analyzed by ICP except Be by SSMS and Hg by cold vapor.

[b] No meaning outlet greater than inlet.

TABLE 4.7-6. TRACE ELEMENT COLLECTION EFFICIENCY FOR A DUAL ALKALI SO_2 SCRUBBER PRECEEDED BY AN ESP

Element	Trace Element Collection Efficiency, % Plant D[a]
Hg	97
Mn	60
V	31.2
Ash	18.9

---

[a] Pulverized coalfired dry bottom utility boiler fired with Eastern bituminous coal, 3.56.3% S. Dual alkali SO_2 scrubber preceeded by ESP. Samples collected by SASS train at a single point in the duct, analyzed by ICP except As by AA and Hg by cold vapor.

Although recovery of trace elements from ash collected by ESP or fabric or sludge from FGD systems may not be feasible, recovery of valuable trace elements from physical coal cleaning wastes is currently under investigation.[37]

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CHAPTER 5

COST IMPACT OF CONTROL TECHNOLOGIES

This chapter discusses the cost impacts of various PM, SO_2, and NO_x control technologies for boilers firing CWM. The cost impacts are evaluated in terms of (1) capital costs, (2) annual operating and maintenance (O&M) costs, (3) annualized costs, and (4) cost effectiveness.

The methodology and assumptions used to develop the costs are discussed briefly in Section 5.1. More detail on the emission control costs can be found in Appendix A of this report. Particulate matter control costs are presented in Section 5.2, while Section 5.3 deals with the costs of FGD for combined SO_2 and PM controls. The annualized cost of alternative techniques for combined SO_2/PM control are compared in Section 5.4. The costs of NO_x control are discussed on a somewhat more qualitative basis than costs for SO_2 and PM control in Section 5.5. The costs associated with coal beneficiation and CWM preparation are examined in Section 5.6.

5.1 COSTING METHODOLOGY AND ASSUMPTIONS

5.1.1 Particulate Matter (PM) and SO_2 Control Costs

The cost impacts of various PM and SO_2 control technologies were evaluated for three CWM boiler sizes and four CWM fuel types. The boiler sizes examined were:

- 8.8 MW (30×10^6 Btu/hr),
- 73 MW (250×10^6 Btu/hr), and
- 205 MW (700×10^6 Btu/hr).

The CWM fuel types for which the control technologies were costed are shown in Table 5.1-1. The information in Table 5.1-1 includes ROM coal, beneficiated coal, and CWM compositions, and uncontrolled CWM emission rates. The fuel compositions were selected from typical coal compositions[1] and based on performance data for various levels of coal beneficiation.[2,3] Uncontrolled SO_2 and PM emission rates were calculated assuming that (1) all of the fuel sulfur is emitted as SO_2 and (2) 80 percent of the ash in the fuel is emitted as fly ash. Each CWM fuel was assumed to be a 70:30 mixture of coal and water.

The costs of PM and SO_2 control technologies presented in this report are based primarily on the technology costs developed by Jennings and Kelly in "Costs of Sulfur Dioxide and Particulate Matter Emission Control for Coal- and Oil-Fired Industrial Boilers."[4] However, two very significant adjustments to those costs have been made for the purposes of this study:

- A retrofit factor was applied to the direct capital cost of the control system. The use of a retrofit factor reflects the fact that emission control systems will likely have to be retrofitted to existing boilers that have been converted to COM-firing.

- Capital and annualized costs were updated from the 1978 dollars used in EPA's study to end-1981 dollars.

5.1.1.1 Retrofit factor--

A factor of 1.5 was used to adjust the direct (equipment and installation) capital cost of a PM or SO_2 control system for a new boiler. This factor reflects the expected higher capital costs of retrofit applications. The 1.5 factor was selected based on information presented in a study of FGD costs for EPA's acid rain program.[5] That study recommended a 1.4 utility system retrofit factor when retrofitting was complex. No information was available for industrial retrofit systems.

TABLE 5.1-1. RAW COALS, CLEANED COALS, AND CLEANED COAL CWMs

	Raw Coal	High-Sulfur Eastern (HSE)	Low-Sulfur Eastern (LSE)	Low-Sulfur Western (LSW)
wt. %, dry basis	C	71.04	80.69	72.73
	H	4.86	4.82	4.04
	N	1.43	1.52	1.52
	O	7.19	5.01	14.14
	S	3.88	0.92	0.76
	Ash	11.60	7.04	6.82
	HHV Btu/lb (dry basis)	12,937	14,160	12,121

	Cleaned Coal	HSE-5	HSE-3&4	LSE-2	LSW-2
wt. %, dry basis	C	80.15	75.54	81.42	73.34
	H	5.48	5.17	4.87	4.07
	N	1.61	1.52	1.53	1.53
	O	8.11	7.65	5.05	14.26
	S	1.16	2.13	0.80	0.66
	Ash	3.48	8.00	6.34	6.14
	HHV Btu/lb (dry basis)	14,596	13,668	14,227	12,221

	Cleaned Coal CWM	"A" HSE-5	"B" HSE-3&4	"C" LSE-2	"D" LSW-2
	Moisture	30.0	30.0	30.0	30.0
wt. %	C	56.11	52.9	57.0	51.3
	H	3.84	3.6	3.4	2.8
	N	1.13	1.1	1.1	1.1
	O	7.7	5.4	3.5	10.0
	S	0.81	1.5	0.56	0.46
	Ash	2.44	5.6	4.4	4.3
	HHV Btu/lb	10,217	9,568	9,994	8,555
	LHV Btu/lb	9,888	9,239	9,665	8,226
	Uncontrolled PM Emissions lb/10^6 Btu	2.0	4.8	3.6	4.2
	Uncontrolled SO_2 Emissions[b] lb/10^6 Btu	1.5	3.2	1.1	1.1

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[a] Assuming 80% of ash exits boiler as fly ash.

[b] Assuming all S exits boiler as SO_2.

Considering the boiler sizes chosen for evaluation and the space limitations likely to be found at many existing oil-fired boiler installations, a 1.5 retrofit factor seemed an appropriate estimate. However, the reader should be cautioned that the 1.5 factor is only a rough estimate of the additional costs that may be incurred in a retrofit situation. The study mentioned above found that factors varied from 0.9 to 3.0 in previous retrofit factor studies. This wide range reflects the fact that retrofit costs are extremely site-specific and indicates the difficulty of selecting a retrofit factor that is applicable to all situations. Only a site-specific evaluation of the factors associated with retrofit, such as space limitations, higher construction costs, and extended construction periods, can accurately quantify the actual retrofit costs.

5.1.1.2 Conversion of $1978 to $ end-1981--

The cost basis for EPA's Industrial Boiler Study was mid-1978 dollars. A factor of 1.40, based on the CE Plant Cost Index,[6] was used to update the costs to end-1981 dollars. The factor was applied to total turnkey costs and to total annual O&M costs. Although labor and chemical costs may not have increased at the same rate as plant costs, a more detailed breakdown of cost update factors did not seem warranted considering the overall accuracy of the cost estimates.

5.1.1.3 Cost Components--

The components of the capital, annual O&M, and annualized costs are shown in Tables 5.1-2 and 5.1-3. Annual O&M costs presented in this chapter are based on a boiler annual capacity of 60 percent. More detailed information on the specific equipment scope, control system design and operating parameters, and unit costs for labor, electricity, water, chemicals, and waste disposal can be found in Appendix A.

5.1.1.4 Other Sources of Cost Estimates--

The costs for dry injection of nahcolite were based on references and information other than that contained in EPA's study for the Industrial

TABLE 5.1-2. CAPITAL COST COMPONENTS

(1) Direct Costs

Equipment
+ Installation
= Total Direct Costs

(2) Indirect Costs

Engineering	(10% of direct costs)
+ Construction and Field Expenses	(10% of direct costs)
+ Construction Fees	(10% of direct costs)
+ Start-up Costs	(2% of direct costs)
+ Performance Costs	(1% of direct costs for FGD and PM systems)
= Total Indirect Costs	

(3) Contingencies = 20% of (Total Indirect + Total Direct Costs)

(4) Total Turnkey Cost = Total Indirect Cost + Total Direct Cost + Contingencies

(5) Working Capital = 25% of Total Direct Operating Costs

(6) Total Capital Cost = Total Turnkey + Working Capital

TABLE 5.1-3. ANNUAL O&M AND ANNUALIZED COST COMPONENTS

Annual O&M Cost Components

(1) Direct Operating Costs

Direct Labor
+ Supervision
+ Maintenance Labor, Replacement Parts, and Supplies
+ Electricity
+ Water
+ Steam
+ Waste Disposal
  Solids (Fly ash and bottom ash)
  Sludge
  Liquid
+ Chemicals

Total Non-Fuel O&M
+ Fuel

= Total Direct Operating Costs

(2) Indirect Operating Costs (Overhead

Payroll (30% Direct Labor)
+ Plant (26% of Direct Labor + Supervision + Maintenance Costs)

= Total Indirect Operating Costs

(3) Total Annual Operating and Maintenance Costs = Total Direct + Total Indirect Costs

Annualized Costs

(1) Total Annualized Cost = Annual Operating Costs + Capital Charges

(2) Capital Charges

= Capital recovery + interest on working capital + miscellaneous (G&A, taxes and insurance)

(3) Calculation of Capital-Related Cost Components

A. Capital Recovery = Capital Recovery Factor (CFR) x Total Turnkey Cost

TABLE 5.1-3. (Continued) ANNUAL O&M AND ANNUALIZED COST COMPONENTS

$$CFR = \frac{i\,(1 + i)^n}{(1 + i)^n - 1}$$

i = interest rate

n = number of years of useful life of boiler or control system

PM control systems - n = 20
SO_2 control systems - n = 15
NO_x control systems - n = 30

B. Interest on Working Capital = 10% of working capital

C. G&A, taxes and insurance = 4% of total turnkey cost

Boiler NSPS. The references used to develop the costs for dry injection are given in the sections of this chapter dealing with that technology.

5.1.2 NO_x Control Costs

The costs of NO_x control through combustion modifications such as low excess air, staged combustion, flue gas recirculation, and low-NO_x burners are extremely boiler-specific. The use of these techniques on some existing boilers may require considerable boiler modification, while their implementation on other boilers may be less costly. And some of these techniques are already incorporated as part of the boiler design. Therefore, NO_x control costs are presented in a more qualitative manner than PM or SO_2 control costs. Additional equipment requirements, such as O_2 monitors or additional fan capacity and boiler modifications that might be required in implementing a particular combustion modification technology are discussed in Section 5.5.

5.2 PARTICULATE MATTER CONTROL COSTS

This section presents the costs for two PM control devices, ESPs and fabric filters, applied to boilers firing CWM. Costs for the ESPs were based on a PM control level of 43 ng/J (0.1 $lb/10^6$ Btu), while costs for the fabric filter were based on a 21 ng/J (0.05 $lb/10^6$ Btu) PM control level. These emission levels were chosen because they are typical of many ESPs and fabric filters. It should be noted, however, that ESPs can be designed to remove PM to a level of 13 ng/J (0.03 ng/J) at increased costs. The control efficiencies required to achieve these emission levels are shown in Table 5.2-1. Documentation of the assumptions and bases used in developing the PM control costs can be found in Appendix A.

5.2.1 ESP Control Costs

5.2.1.1 Capital Costs--

TABLE 5.2-1. PM REMOVAL EFFICIENCIES OF ESP AND FABRIC FILTER FOR VARIOUS CWM FUELS

CWM Fuel	Uncontrolled PM Emissions ng/J	(lb/10^6 Btu)[a]	PM Removal, Efficiency % ESP[b]	Fabric Filter[c]
A	860	(2.0)	95.0	97.5
B	2,064	(4.8)	97.9	99.0
C	1,548	(3.6)	97.2	98.6
D	1,806	(4.2)	97.6	98.8

[a] Assuming that 80% of the ash contained in the CWM leaves as fly ash.

[b] PM emission control level of 43 ng/J (0.1 lb/10^6 Btu).

[c] PM emission control level of 21 ng/J (0.05 lb/10^6 Btu).

Capital costs for ESPs applied to CWM-fired boilers are shown in Figure 5.2-1. Capital costs for ESPs applied to "A" fuels are the lowest, ranging from about \$800,000 for a 8.8 MW (30 x 10^6 Btu/hr) boiler to \$6,200,000 for a 205 MW (700 x 10^6 Btu/hr) boiler. The highest ESP capital costs are for "D" fuels and range from \$900,000 to \$6,900,000 for the same range of boiler sizes.

ESP capital costs are dependent upon both the ash and the sulfur contents of a CWM. CWMs with high ash content require ESPs with large specific collection areas in order to achieve the desired PM emissions level of 43 ng/J (0.10 Btu/lb). Low-sulfur CWMs may also require ESPs with large specific collection areas due to the increased resistivity of fly ash particles (see Section 4.4.1). The capital costs increase as the ESP size increases with increasing collection area requirements. ESP capital costs presented in this report are based on specific collection areas of 300 ft^2/1000 acfm for "A" and "B" fuels and 350 ft^2/1000 acfm for "C" and "D" fuels.

5.2.1.2 Annual O&M and Annualized Costs--

Figure 5.2-2 presents both annual O&M and annualized costs for ESPs applied to CWM boilers. The annual O&M costs are based on a 60 percent annual capacity factor.

Annual O&M costs shown in Figure 5.2-2 range from \$50,000 to \$420,000 for boilers ranging in size from 8.8 MW (30 x 10^6 Btu/hr) to 205 MW (700 x 10^6 Btu/hr). Annual O&M costs are lowest for "A" fuels and highest for the high-ash "B" and "D" fuels. This difference in O&M costs for the different fuels is a result of the larger quantities of solid waste generated for disposal by the "B" and "D" fuels compared to the "A" fuels.

The annualized costs for ESPs applied to CWM boilers vary from \$175,000 to \$1,485,000 over the range of boiler sizes examined. Again, the

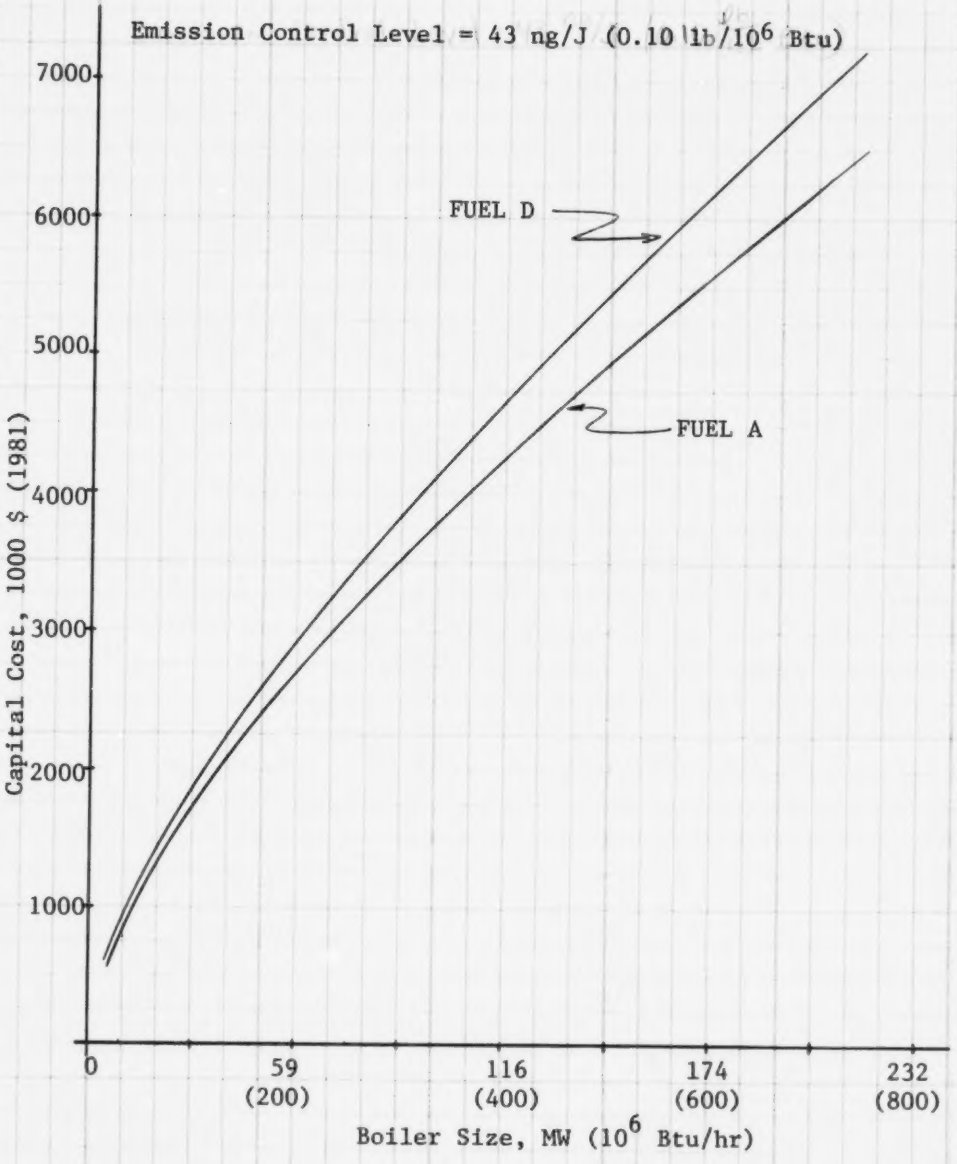


Figure 5.2-1. Capital costs of ESPs applied to CWM boilers.

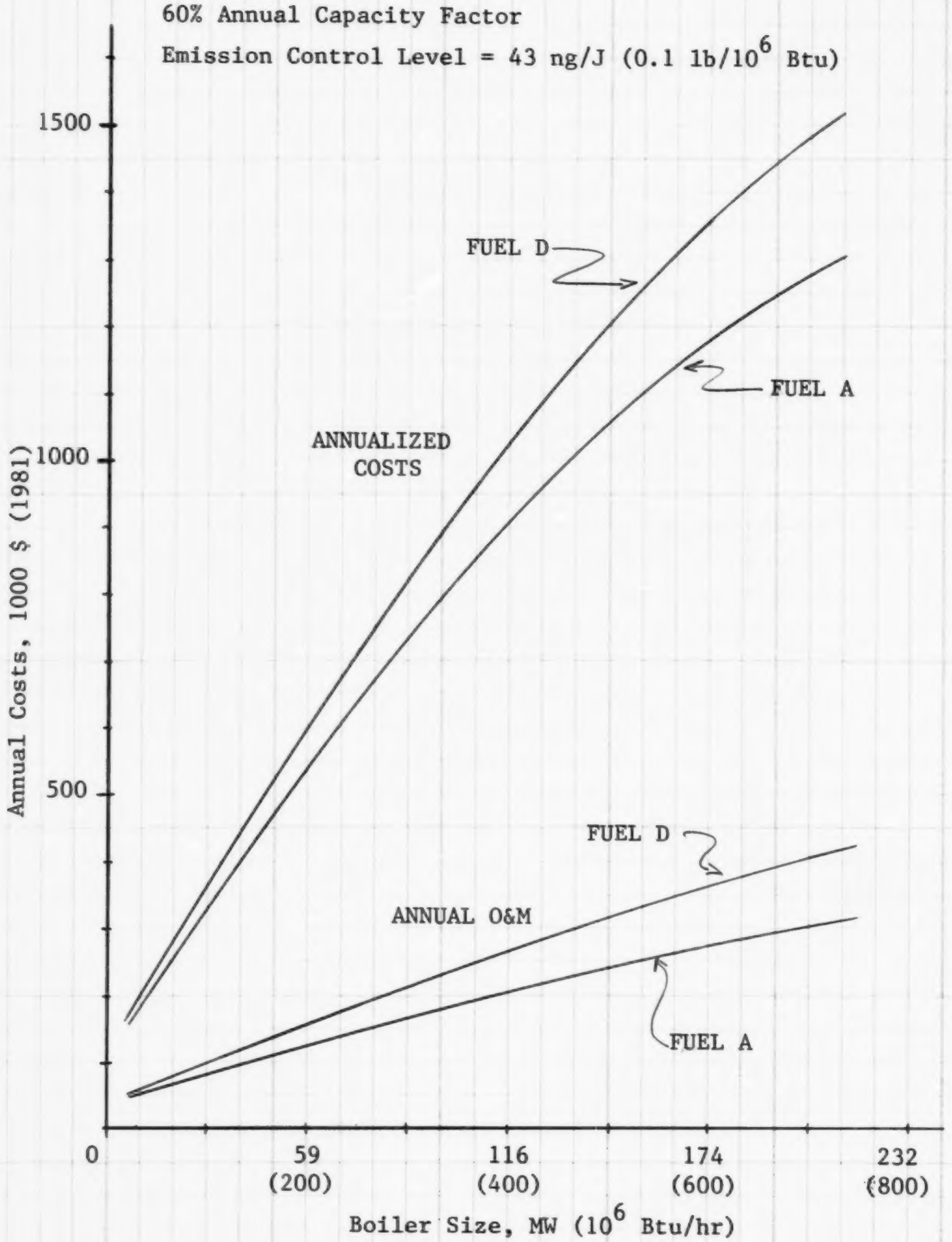


Figure 5.2-2. Annual costs for ESPs applied to CWM boilers.

annualized costs for ESPs applied to "A" fuels are lowest and are highest for ESPs applied to "D" fuels.

Figure 5.2-3 presents the annualized costs of the ESP normalized to a boiler heat input basis. The cost impact of the ESP on a normalized basis decreases with increasing boiler size, ranging from about $\$1.20/10^6$ Btu to $\$0.40/10^6$ Btu for the boiler sizes examined.

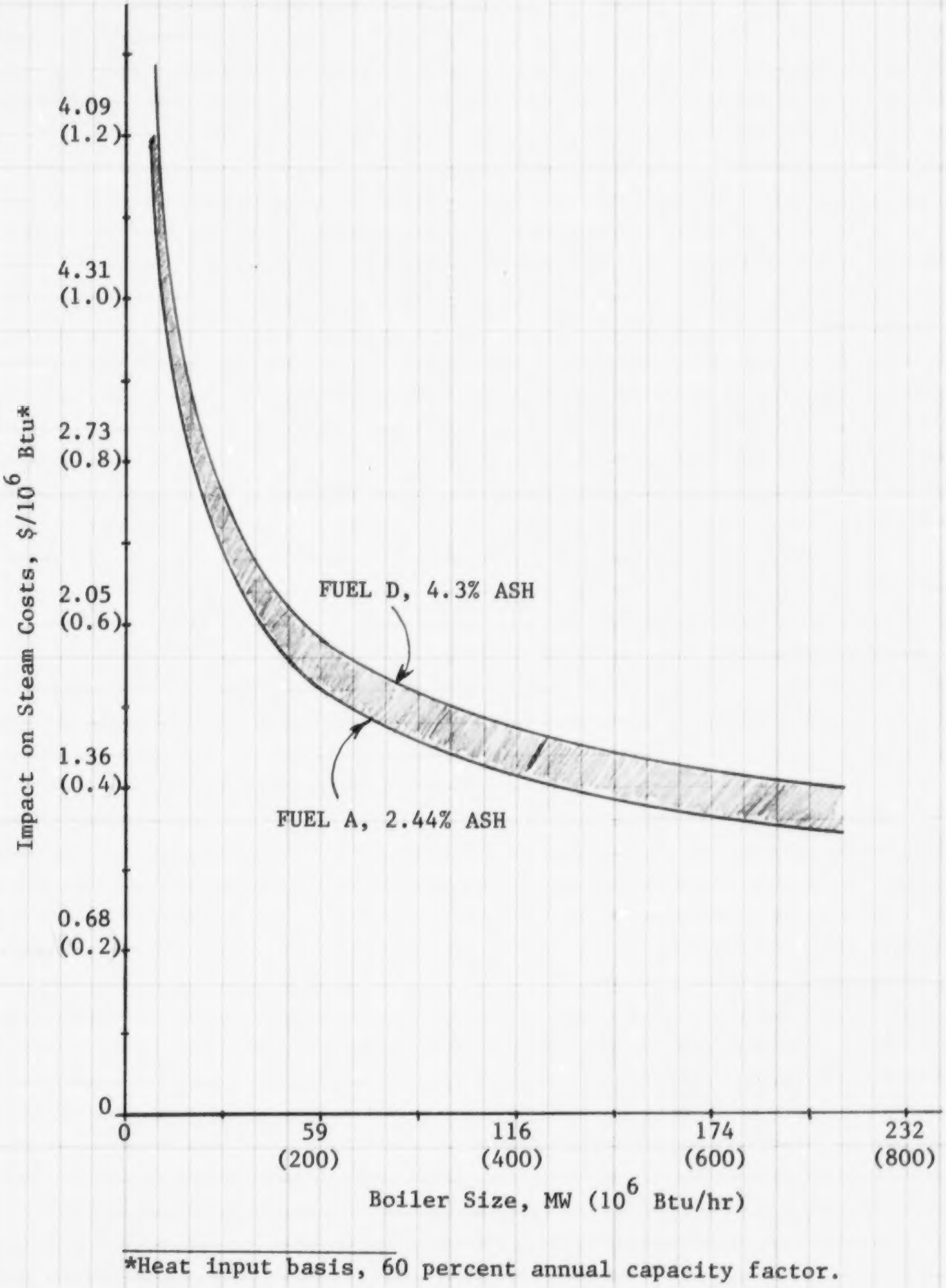
5.2.1.3 Cost Effectiveness--

The cost per ton of PM removed is shown in Figure 5.2-4 for the three boiler sizes examined: 8.8 MW (30×10^6 Btu/hr), 73 MW (250×10^6 Btu/hr), and 205 MW (700×10^6 Btu/hr). Two trends are evident in this figure: (1) the cost effectiveness of ESP control improves (lower cost per ton removed) as boiler size increases and (2) for a given boiler size, the cost effectiveness is better for higher ash CWM fuels. The cost per ton of PM removed is significantly higher for the "A" fuels than for the "B", "C" and "D" fuels. For example, the cost per ton of PM removed when burning fuel "A" ranges from about $1160 to $370 for the 8.8 MW ($30 \times 10^6$ Btu/hr) and 205 MW (700×10^6 Btu/hr) boiler sizes, respectively. For "B" fuels, the cost per ton of PM removed with the ESP varies from about $480 to $170 for the boiler sizes examined. The cost effectiveness of ESPs applied to "B" fuels is about one-third of the cost per ton of PM removed for "A" fuels.

5.2.2 Fabric Filter Control Costs

5.2.2.1 Capital Costs--

The capital costs of fabric filters applied to CWM are presented in Figure 5.2-5. The capital cost for fabric filters depends primarily on the flue gas flow rate, and is not a function of CWM fuel properties. Thus, as shown in Figure 5.2-6, fabric filter capital costs are approximately equal for all CWM fuels. Figure 5.2-6 indicates capital costs ranging from about $410,000 for a 8.8 MW ($30 \times 10^6$ Btu/hr) boiler to $6,400,000 for a 205 MW ($700 \times 10^6$ Btu/hr) boiler.



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*Heat input basis, 60 percent annual capacity factor.

Figure 5.2-3. Range of impact of ESP on steam costs.

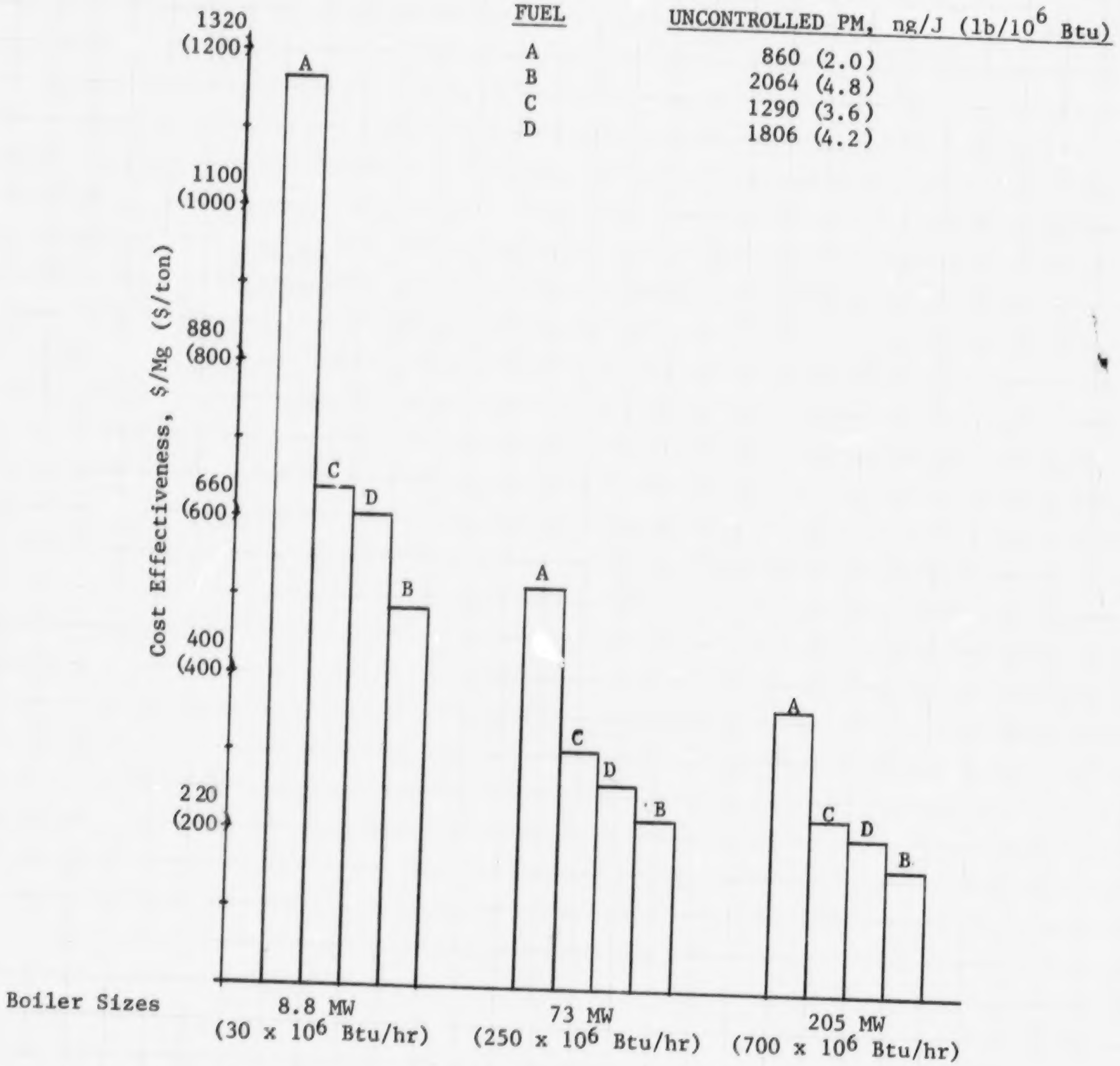


Figure 5.2-4. Cost effectiveness of ESPs on CWM boilers.

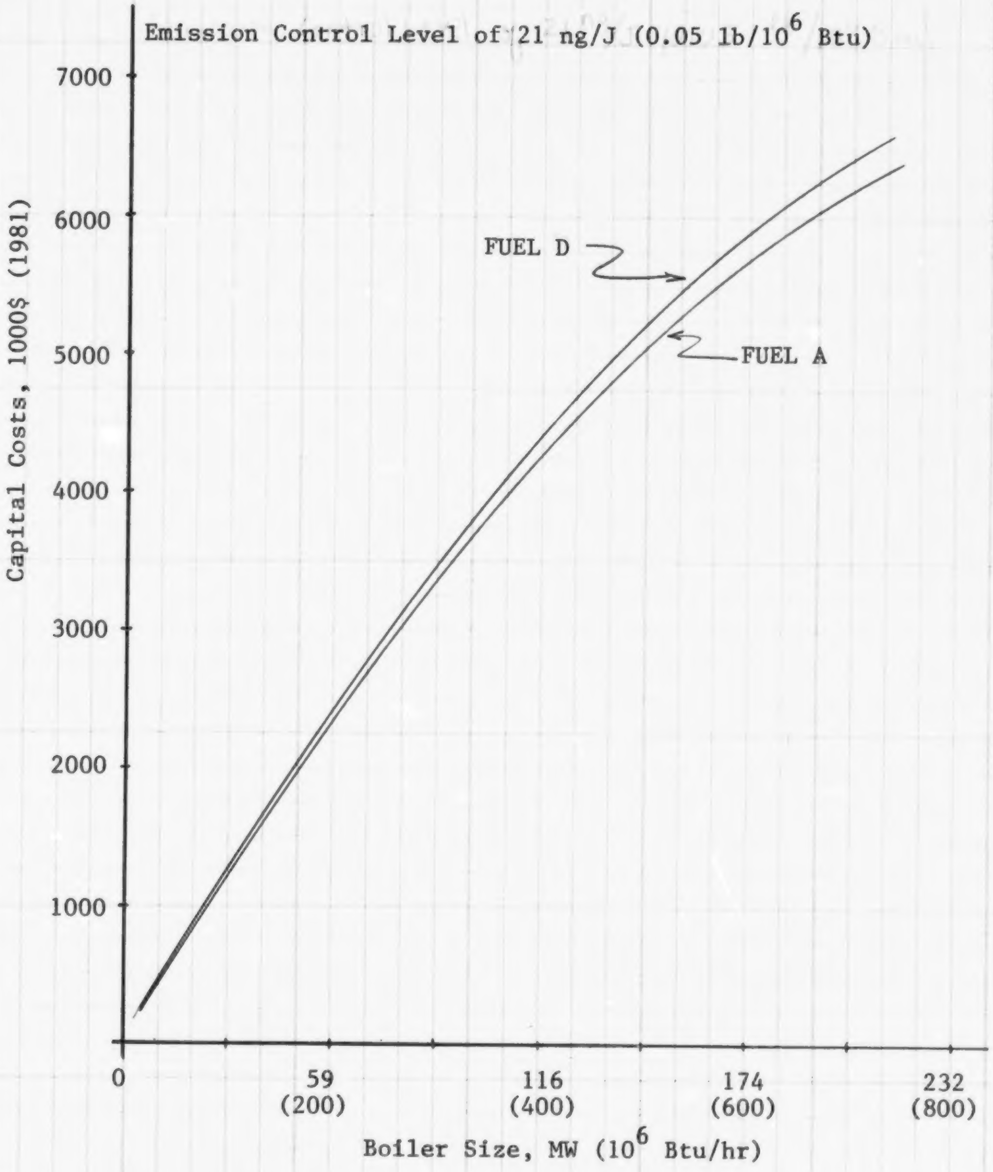


Figure 5.2-5. Capital costs of fabric filters applied to CWM boilers.

Comparison of fabric filter capital costs to those presented in Section 5.2.1 for ESPs indicates that fabric filters are less expensive for all boiler sizes and CWM fuels evaluated, with the greatest differences for the "C" and "D" fuels. Over the range of boiler sizes examined, capital costs for fabric filters were $400,000 to $500,000 lower than for ESPs. Fabric filters for "A" and "B" fuels are considerably less expensive than ESPs when applied to small boilers. But the capital cost differential decreases with increasing boiler size such that the costs of these controls are approximately equal when applied to a 205 MW (700 x 10^6 Btu/hr) boiler firing "A" or "B" fuels.

5.2.2.2 Annual O&M and Annualized Costs--

Annual O&M costs for fabric filters applied to CWM-fired boilers are presented in Figure 5.2.6. These costs are based on a 60 percent annual capacity factor. As with ESPs, the higher ash CWMs have higher annual O&M costs, due largely to the cost of solid waste disposal. Annual O&M costs for fabric filters vary from $60,000 to $600,000 over the range of boiler sizes examined. The annual O&M costs for fabric filters are higher than those of ESPs. This is to be expected, however, due to the increased fly ash collection efficiencies of fabric filters used in this study.

Figure 5.2-6 also presents the annualized costs for fabric filters on CWM boilers. These costs range from $120,000 for a 8.8 MW (30 x 10^6 Btu/hr) boiler to $1,600,000 for a 205 MW (700 x 10^6 Btu/hr) boiler.

Figure 5.2-7 presents the annualized costs for fabric filters normalized to a heat input basis. The cost impact of fabric filters ranges from $2.73/MWh ($0.80/10^6 Btu) for a 8.8 MW (30 x 10^6 Btu/hr) boiler to about $1.53/MWh ($0.45/10^6 Btu) for a 205 MW (700 x 10^6 Btu/hr) boiler. The comparable ESP costs ranged from $4.09/MWh ($1.20/10^6 Btu) to $1.36/MWh ($0.40/10^6 Btu), indicating the lower cost of PM collection by fabric filtration for smaller boiler sizes.

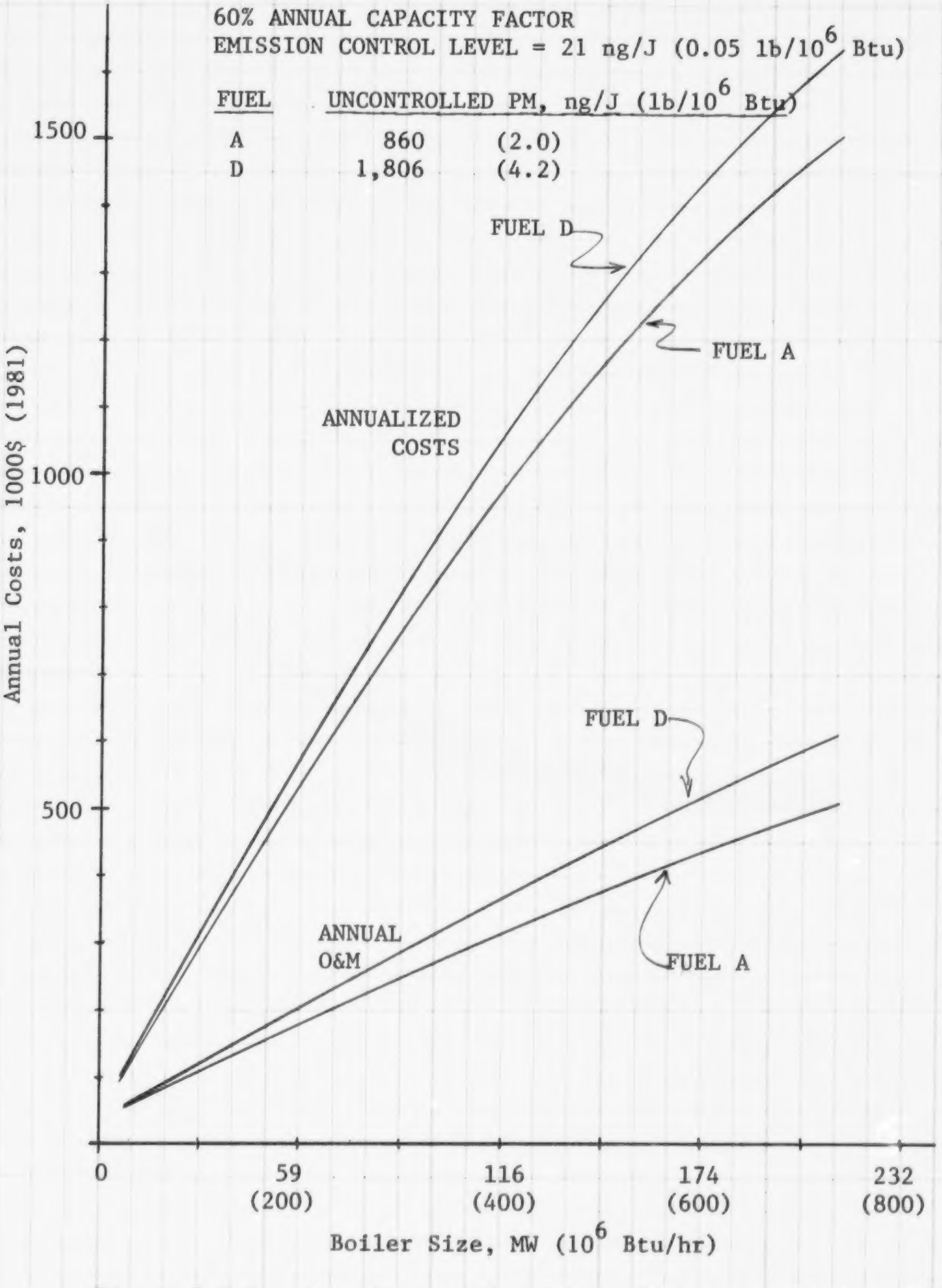
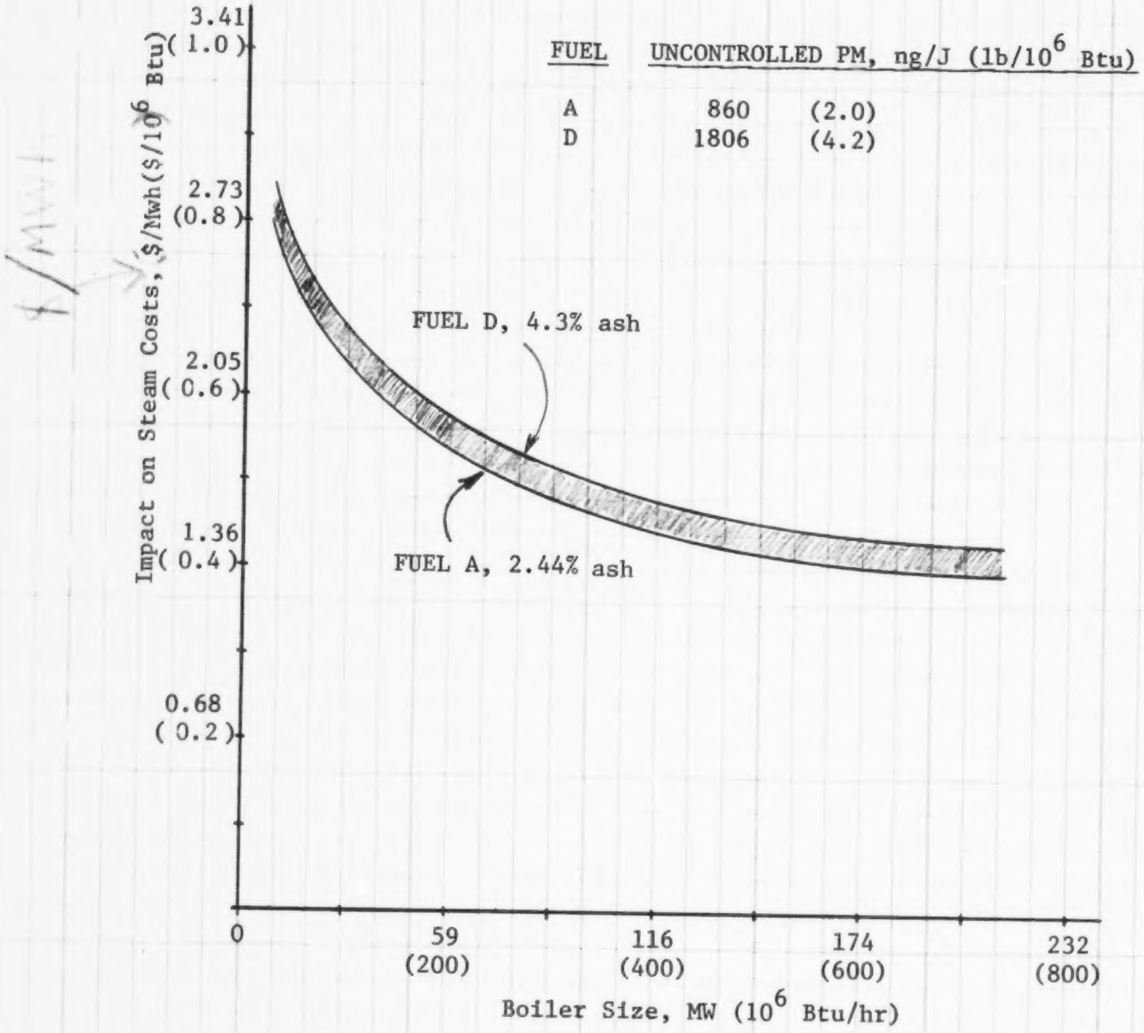


Figure 5.2-6. Annual costs for fabric filters applied to CWM boilers.



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*Heat input basis, 60 percent annual capacity factor.

Figure 5.2-7. Range of impact of fabric filter on steam costs.

5.2.2.3 Cost Effectiveness--

The cost per ton of PM removed with fabric filters is shown in Figure 5.2-8. The cost effectiveness of fabric filters improves with increasing boiler size and increasing CWM ash content. The cost effective- ness of fabric filters applied to boilers firing "A" fuels extends from about \$869/mg (\$790/ton) for a 8.8 MW (30 x 10^6 Btu/hr) boiler to \$451/Mg (\$410/ton) of PM removed for a 205 MW (700 x 10^6 Btu/hr) boiler. The corresponding cost effectiveness values for ESPs ranges from \$1276 to \$407/mg (\$1160 to \$370/ton) of PM removed. Similarly, the cost effectiveness of fabric filters applied to boilers firing "B" fuels ranges from about \$374 to \$198/mg (\$340 to \$180 ton) of PM removed for the range of boiler sizes evaluated, with comparable costs for ESPs ranging from \$531 to \$176/mg (\$483 to \$160/ton).

In comparing the cost effectiveness of fabric filters to ESPs for various boiler sizes and CWM fuels, the following trends become apparent:

(1) Fabric filters are significantly more cost effective for 8.8 MW (30 x 10^6 Btu/hr) boilers firing CWMs;

(2) ESPs are slightly more cost effective for 205 MW (700 x 10^6 Btu/hr) boilers; and

(3) Fabric filters and ESPs are equally cost effective when applied to 73 MW (250 x 10^6 Btu/hr) boilers firing CWMs.

These trends are explained by differences between the capital, replacement parts, and utility costs of fabric filters and ESPs. The capital cost of fabric filters for a 8.8 MW (30 x 10^6 Btu/hr) boiler are significantly lower than those of an ESP. And replacement parts and utility costs are approximately equal. But fabric filter capital, replacement parts, and utility costs increase more steeply than do ESP costs. For a 205 MW (700 x 10^6 Btu/hr), capital costs for ESPs and fabric filters are essentially equal. But replacement parts and utility costs for fabric filters are greater than those of ESPs.

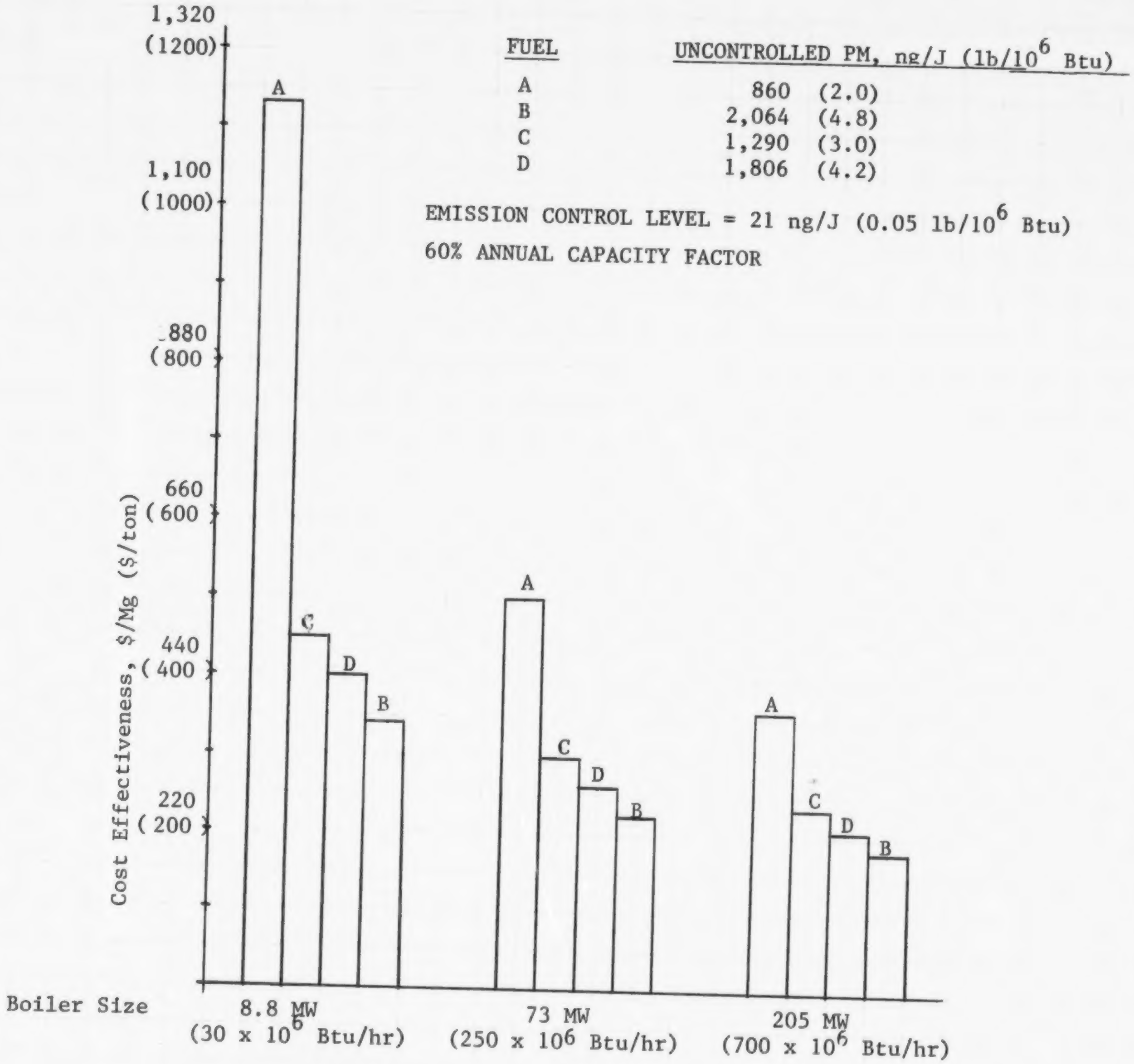

Figure 5.2-8. Cost effectiveness of fabric filters on CWM boilers.

5.3 COMBINED SO_2/PM CONTROL WITH FGD SYSTEMS

This section presents the costs for three FGD technologies capable of controlling both SO_2 and PM emissions from CWM combustion. The technologies evaluated are:

- dual alkali wet FGD,
- lime spray drying, and
- dry injection of nahcolite.

Costs for both the spray drying and dry injection FGD systems include the costs for a fabric filter. The fabric filter is required for collection of fly ash and the dry waste solids produced by desulfurization. Costs for the dual alkali wet FGD system are based on a venturi-type scrubber and include costs for a mechanical collector located upstream of the scrubber. The mechanical collector is assumed to capture 80 percent of the fly ash leaving the boiler before the flue gas enters the scrubber. Although lime and limestone wet FGD costs were not specifically evaluated in this report, they are expected to be very similar to dual alkali FGD system costs.[7]

There are several assumptions and bases used in developing the wet and dry FGD system costs that are important for the interpretation of the cost data presented in this section. The most important assumptions and bases are highlighted in Table 5.3-1.

To evaluate FGD system costs adequately, as many as three levels of SO_2 removal were examined for each FGD system type and CWM fuel sulfur content. The matrix of SO_2 removal levels, CWM fuel types, and resulting SO_2 emission levels examined for the various FGD systems is shown in Table 5.3-2. The number and type of cases examined for dry injection were scaled back somewhat from the cases used to examine wet FGD and spray drying FGD costs. The number of dry-injection cases examined is limited due primarily to a

TABLE 5.3-1. IMPORTANT ASSUMPTIONS AND BASES USED TO DEVELOP FGD SYSTEM COSTS

General

- Capital costs for FGD systems are based on a retrofit factor of 1.5 (used to adjust the direct capital costs).
- Labor costs are based on 1 full-time operator and ¼-time supervisor.
- Waste sludge and solids are assumed to be disposed of off-site at a rate of \$16/Mg (\$15/ton) [\$0.0166/kg] (\$1978).
- All costs are based on scrubbing 100% of the flue gas (no partial scrubbing).

Wet FGD Systems

- Capital costs are based on shop-fabricated equipment; single scrubber for 8.8 MW (30 x 10^6 Btu/hr) and 73 MW (250 x 10^6 Btu/hr) units; 3 scrubbers for 205 MW (700 x 10^6 Btu/hr) units.
- Stack gas reheat is not included in capital or annual costs.
- Reagent costs (\$1978):

  Sodium carbonate: \$0.099/kg (\$99/Mg[\$90/ton])

  Lime: \$0.039/kg (\$39/Mg[\$35/ton])

Spray Dryer Systems

- Capital costs are based on single shop-fabricated spray dryer for all boiler sizes examined.
- Reagent costs (\$1978):

  Lime: \$0.039/kg (\$39/mg[\$35/ton])

Dry Injection Systems[a]

- Capital costs are scaled-down from theoretical study of a large utility system (high degree of uncertainty.)
- Reagent costs (\$1978), (also quite uncertain):

  Nahcolite: \$0.042/kg (\$42/mg[\$38/ton])

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[a] For further discussion of the relative certainty of the dry injection costs, see Section 5.3.3.

TABLE 5.3-2. SO_2 CONTROL LEVELS AND CWM FUELS EVALUATED FOR FGD SYSTEMS

CWM Fuel	Sulfur Content (%)	Uncontrolled SO_2 Emissions ng/J	Uncontrolled SO_2 Emissions (lb/10^6 Btu)	SO_2 Control Levels Examined: SO_2 Removal (%)	SO_2 Control Levels Examined: Controlled SO_2 Emissions ng/J	SO_2 Control Levels Examined: Controlled SO_2 Emissions (lb/10^6 Btu)
Dual Alkali Wet FGD and Spray Drying FGD						
A	0.81	705	(1.64)	50	353	(0.82)
				70	211	(0.49)
				90	69	(0.16)
B	1.50	1,400	(3.25)	50	701	(1.63)
				70	421	(0.98)
				90	142	(0.33)
C	0.56	499	(1.16)	50	249	(0.58)
				70	151	(0.35)
				90	52	(0.12)
D	0.46	482	(1.12)	50	241	(0.56)
				70	146	(0.34)
				90	47	(0.11)
Dry Injection of Nahcolite						
A	0.81	705	(1.64)	70	211	(0.49)
B	1.50	1,400	(3.25)	70	421	(0.98)
C	0.56	499	(1.16)	70	151	(0.35)
D	0.46	482	(1.12)	70	146	(0.34)

lack of full-scale process data useful for costing dry injection at high SO_2 removal (90 percent).

Capital, annual O&M, and annualized costs for each of the three FGD processes are presented in the following sections. Cost effectiveness and normalized steam cost data are also presented. Section 5.3.4 compares the costs of the three technologies as a function of boiler size and CWM sulfur and ash content.

5.3.1 Wet FGD System Costs

5.3.1.1 Capital Costs--

Capital costs for dual alkali wet FGD systems are presented in Figure 5.3-1 as a function of boiler size and SO_2 removal efficiency for "A" and "B" CWM fuels. The capital costs for removal efficiencies between 50 and 90 percent can be determined by linear interpolation of the figure. The capital costs for "C" and "D" fuels lie within the range of costs bounded by the "A" and "B" fuels.

The capital costs of a dual alkali FGD system applied to a boiler firing "A" fuel are lower than costs for boilers firing "B", "C", or "D" fuels. The capital costs for 50 percent SO_2 removal vary from $1,000,000 for a 8.8 MW (30 x 10^6 Btu/hr) boiler to $4,000,000 for a 205 MW (700 x 10^6 Btu/hr) boiler. The increased costs associated with increasing SO_2 removal from 50 to 90 percent are minimal for the smaller boiler sizes but become more significant as boiler size increases. The capital costs for 90 percent removal increase from $1,000,000 to $4,000,000.

The highest capital costs computed for a dual alkali FGD system were for a boiler firing "B" fuel. Capital costs for 50 percent SO_2 removal increase from $1,000,000 for a 8.8 MW (30 x 10^6 Btu/hr) boiler to $5,000,000 for a 205 MW (700 x 10^6 Btu/hr) boiler. For 90 percent SO_2 removal, these costs vary from $1,000,000 to $5,000,000.

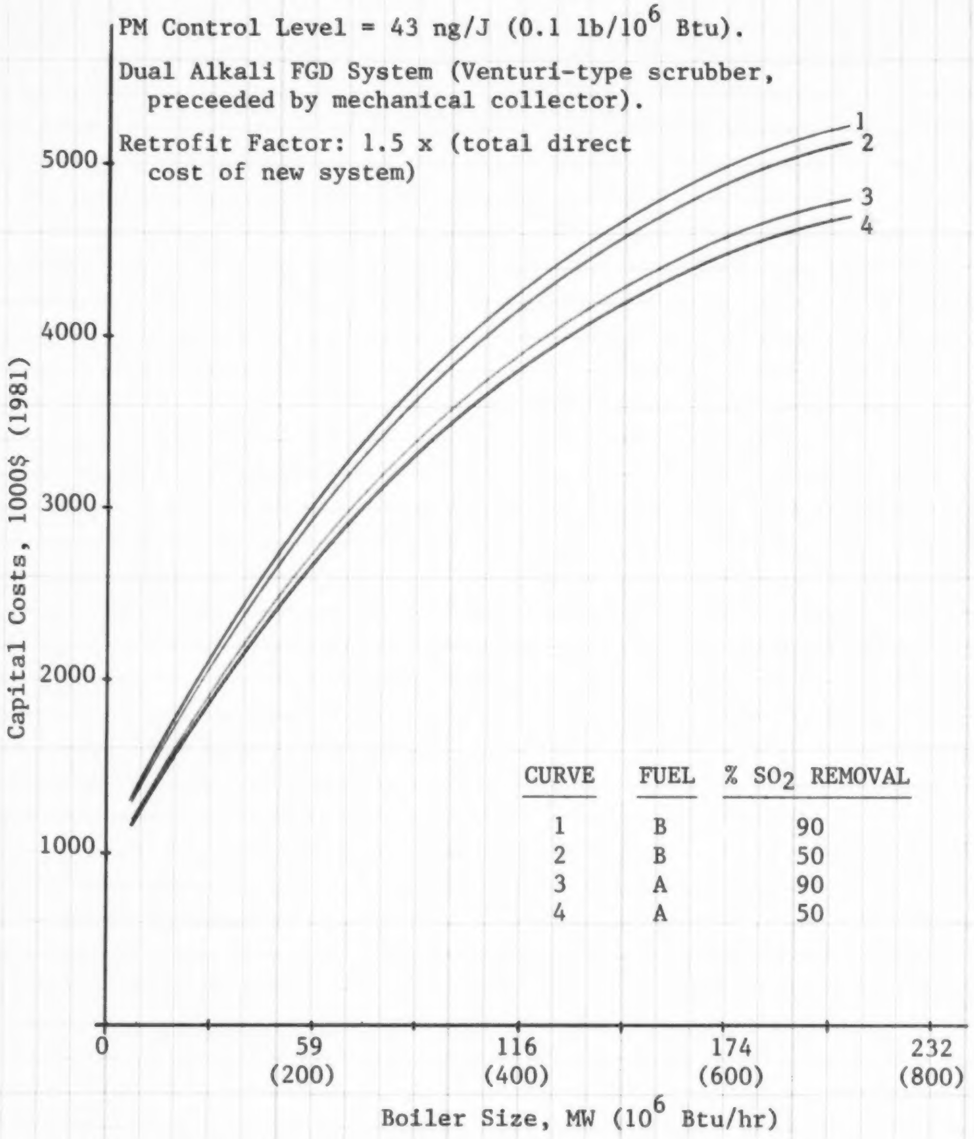


Figure 5.3-1. Capital costs of dual alkali FGD for CWM boilers.

The capital costs for dual alkali wet FGD systems are not entirely dependent upon boiler size and SO_2 removal efficiency. Capital costs are also very sensitive to the ash content of the CWM fuel. The capital costs presented in this section include the use of a mechanical collector to achieve 80 percent PM removal. Additional PM is removed in the FGD system itself, reducing PM emissions to 43 ng/J (0.10 lb/10^6 Btu).

Thus, capital costs of wet FGDs applied to CWM-fired boilers are lowest for fuels with low to moderate ash and sulfur content and highest for fuels with high ash and sulfur contents.

5.3.1.2 Annual O&M and Annualized Costs--

Figure 5.3-2 illustrates the range of annual O&M and annualized costs associated with dual alkali FGD systems applied to CWM-fired boilers. Of the cases examined, the lowest annual O&M and annualized costs resulted when wet FGD systems achieving 50 percent SO_2 removal were applied to boilers firing "A" fuels (low ash, sulfur). The highest costs were for 90 percent SO_2 removal and "B" fuels (moderate ash, sulfur). As with capital costs, annual costs for intermediate removal efficiencies may be determined by linear interpolation of the figures.

Annual O&M costs range from $350,000 to $370,000 for wet FGD systems applied to 8.8 MW (30 x 10^6 Btu/hr) boilers, and from $810,000 to $1,000,000 for 205/MW (700 x 10^6 Btu/hr) boilers. These costs are based on a boiler annual capacity factor of 60 percent. The difference in cost resulting from the use of various CWM fuels is largely due to differences in solid waste handling and disposal requirements. For specific applications, costs may differ somewhat from those shown here due to site-to-site variations in hourly labor and reagent costs, boiler capacity factor, system reliability (maintenance costs), and waste disposal practices.

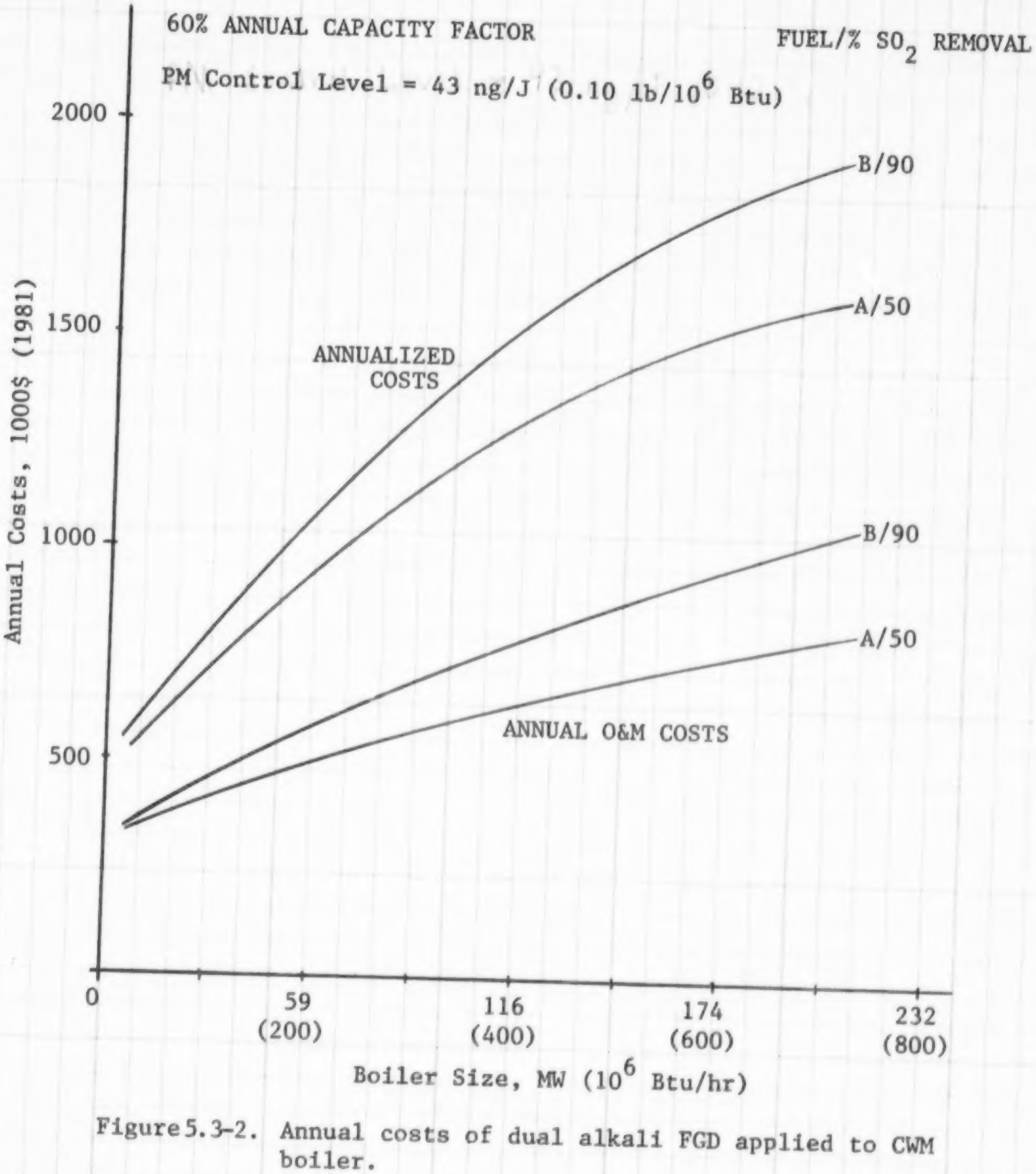


Figure 5.3-2. Annual costs of dual alkali FGD applied to CWM boiler.

Annualized costs vary from \$550,000 to \$600,000 for wet FGD systems applied to 8.8 MW (30 x 10^6 Btu/hr) boilers, and from \$1,590,000 to \$1,900,000 for 205 MW (700 x 10^6 Btu/hr) boilers.

Figure 5.3-3 shows the range of normalized annualized costs for the boiler sizes, SO_2 removal, and CWM fuels examined. The impact on steam cost did not differ significantly among the CWM fuels or with varying SO_2 removal efficiencies. Normalized costs for a 8.8 MW (30 x 10^6 Btu/hr) boiler ranged from \$3.50 to \$3.80 per million Btu heat input. For a 205 MW (700 x 10^6 Btu/hr) boiler, normalized steam costs ranged from \$1.47 to \$1.77/MWh (\$0.43 to \$0.52/10^6 Btu) heat input.

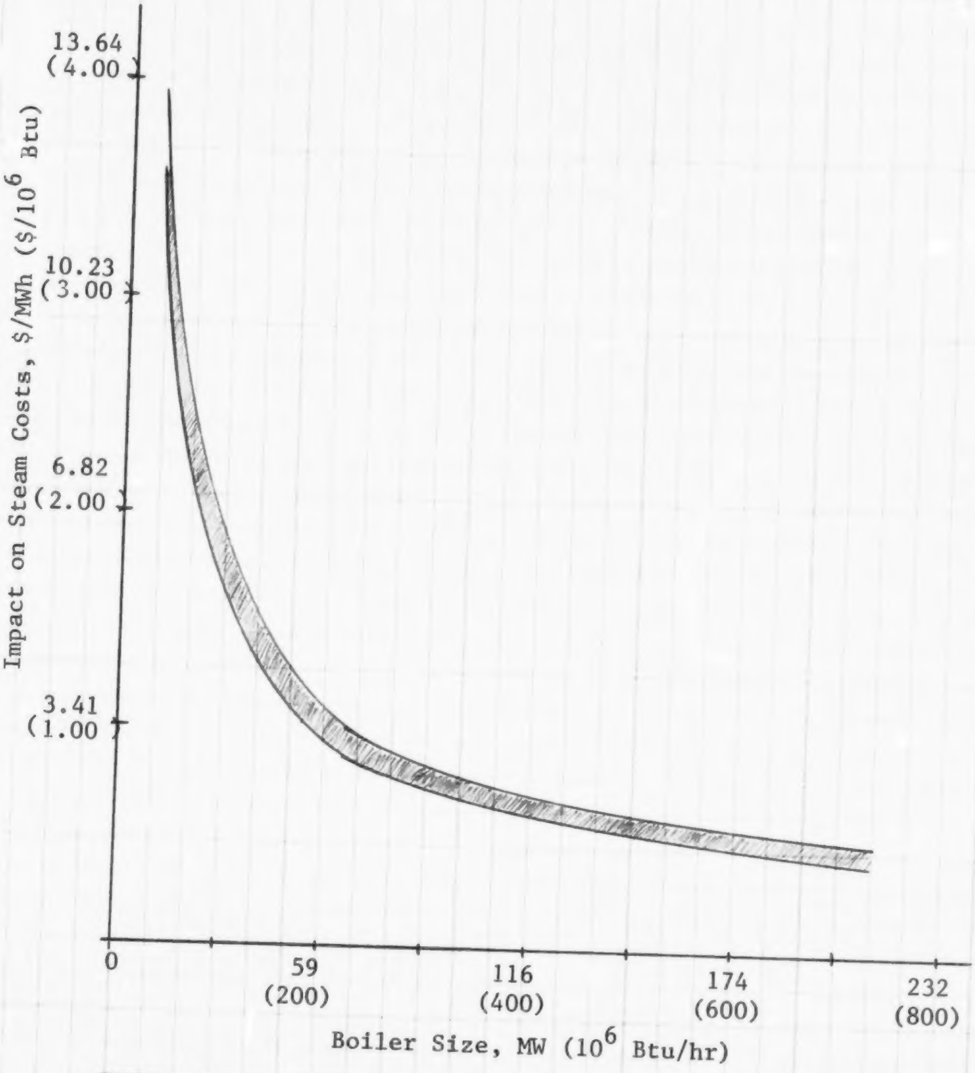
It is difficult to make a meaningful evaluation of cost effectiveness of combined PM/SO_2 control techniques (wet FGD, spray drying FGD, and dry injection FGD) since two pollutants are collected. But is possible to outline factors which affect cost effectiveness:

- Cost effectiveness improves dramatically as boiler size increases.

- The cost per ton of SO_2 removed decreases as the overall SO_2 removal increases (for the range of removals evaluated). That is, for a given fuel and boiler size, 90 percent SO_2 removal is more cost effective than 70 percent SO_2 removal, which is more cost effective than 50 percent SO_2 removal.

- The cost per ton of SO_2 removed decreases as the CWM sulfur content increases. That is, for a given SO_2 removal and boiler size, the cost effectiveness will be better for higher sulfur fuels.

- The cost per ton of PM removed decreases as the CWM ash content increases.



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*Heat input basis, 60 percent annual capacity factor.

Figure 5.3-3. Range of impact on steam costs for dual alkali FGD applied to CWM boilers.

5.3.2 Lime Spray Drying System Costs

5.3.2.1 Capital Costs--

The capital costs for lime spray drying systems applied to CWM- fired boilers are presented in Figure 5.3-4. System costs include the costs of a fabric filter used to capture the spray-dried solids as well as fly ash. The retrofit factor of 1.5 was applied to the direct capital costs of the spray drying process equipment and to the costs of the fabric filter. This represents a median estimate since, as stated previously, retrofit factors may vary significantly from site to site.

As with fabric filters for PM control, the capital costs for lime spray drying FGD systems do not vary significantly with ash content, sulfur content, or removal efficiency. For example, the costs of a lime spray drying FGD applied to a 8.8 MW (30 x 10^6 Btu/hr) boiler range from $1,100,000 for an "A" fuel with 50 percent removal to $1,200,000 for a "B" fuel with 90 percent SO_2 removal. The capital costs for a 205 MW (700 x 10^6 Btu/hr) boiler range from $10,300,000 to $10,600,000. Spray drying FGD capital costs are most sensitive to the ash content of the CWM, increasing with increasing ash content.

5.3.2.2 Annual O&M and Annualized Costs--

Annual O&M and annualized costs for spray drying FGD applied to CWM-fired boilers are shown in Figure 5.3-5. Again, these costs are more sensitive to CWM ash content than to CWM sulfur content or SO_2 removal efficiency. Spray drying FGD systems are equipped with fabric filters which reduce the PM emissions to 21 ng/J (0.05 lb/10^6 Btu). The increased solid waste disposal requirements associated with the use of high-ash fuels as opposed to low-ash fuels substantially impact annual O&M costs. For example, waste disposal costs account for about 32 to 53 percent of the total O&M costs determined for a 8.8 MW (30 x 10^6 Btu/hr) boiler. For a 205 MW (700 x 10^6 Btu/hr), waste disposal costs represent 22 to 39 percent of the total annual O&M costs.

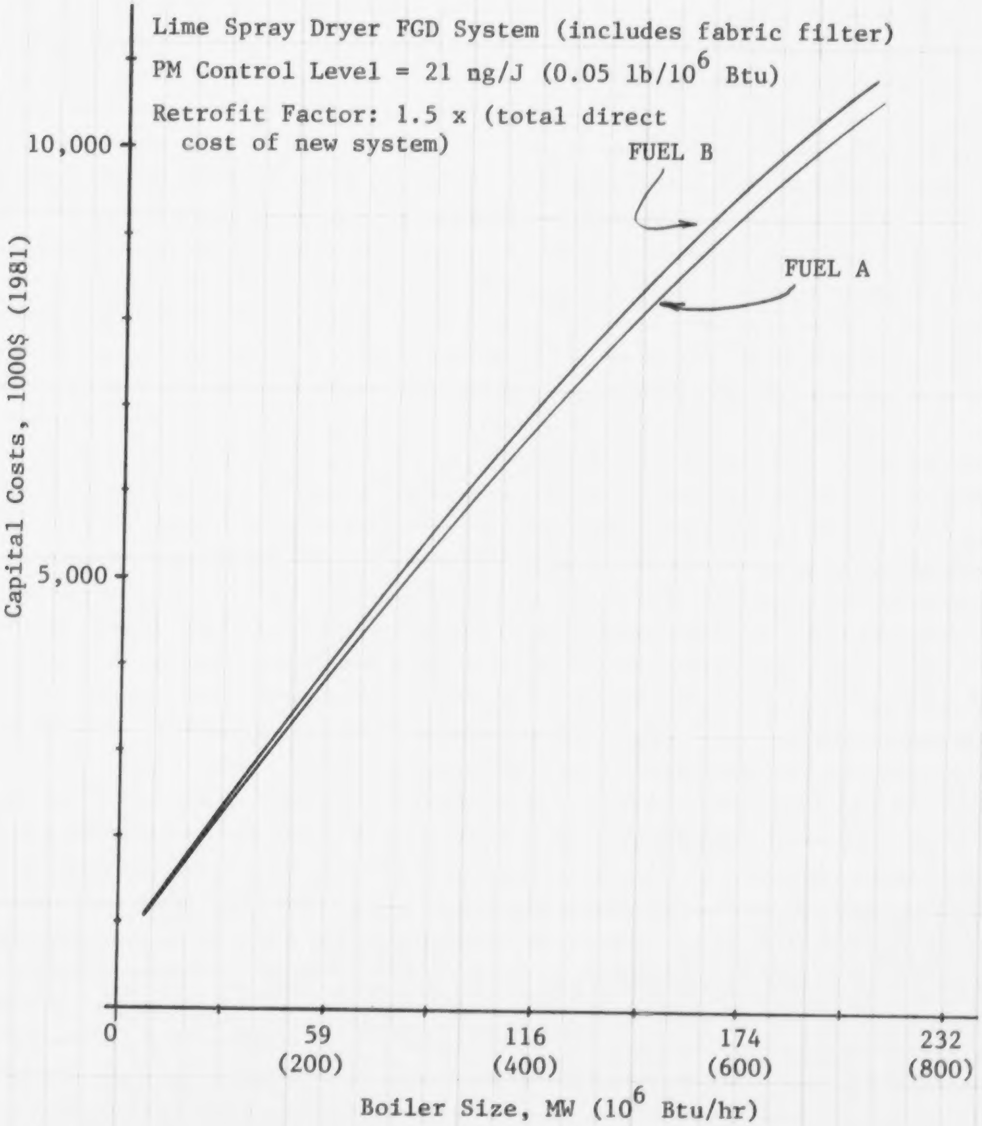


Figure 5.3-4. Capital costs of lime spray drying FGD applied to CWM boilers.

Figure 5.3-5 shows that annual O&M costs for spray drying FGD systems range from \$420,000 to \$570,000 for a 8.8 MW (30 x 10^6 Btu/hr) boiler. For a 205 MW (700 x 10^6 Btu/hr) boiler, annual O&M costs range from \$650,000 to \$840,000. These costs are based on a 60 percent boiler annual capacity factor.

Annualized costs shown in Figure 5.3-5 range from \$610,000 to \$770,000 for a 8.8 MW (30 x 10^6 Btu/hr) boiler and from \$2,400,000 to \$2,700,000 for a 205 MW (700 x 10^6 Btu/hr) boiler.

Annualized costs normalized to a heat input basis are presented in Figure 5.3-6. These costs range from \$3.90 to \$4.90 per million Btu for a 8.8 MW (30 x 10^6 Btu/hr) boiler and from \$0.65 to \$0.72 per million Btu heat input for a 205 MW (700 x 10^6 Btu/hr) boiler. These normalized costs are based on a 60 percent boiler annual capacity factor.

As previously mentioned in the discussion of wet FGD costs, it is difficult to make a meaningful assessment of cost effectiveness for combined PM/SO_2 control techniques. In general terms, the cost effectiveness of spray drying FGD systems for combined PM/SO_2 control follows the same trends discussed in Section 5.3.2.

5.3.3 Dry Injection Systems Costs

5.3.3.1 Capital Costs--

Estimated capital costs for dry injection of nahcolite, which include the costs of a retrofitted fabric filter, are shown in Figure 5.3-7. These costs are based on 70 percent SO_2 removal. Of the four CWM fuels evaluated, Fuel "C" had the lowest capital costs and Fuel "B" had the highest. But, as shown in Figure 5.3-7, capital costs for dry injection systems do not vary significantly with the ash or sulfur content of the CWM. The costs derived for dry injection FGD have a somewhat higher degree of

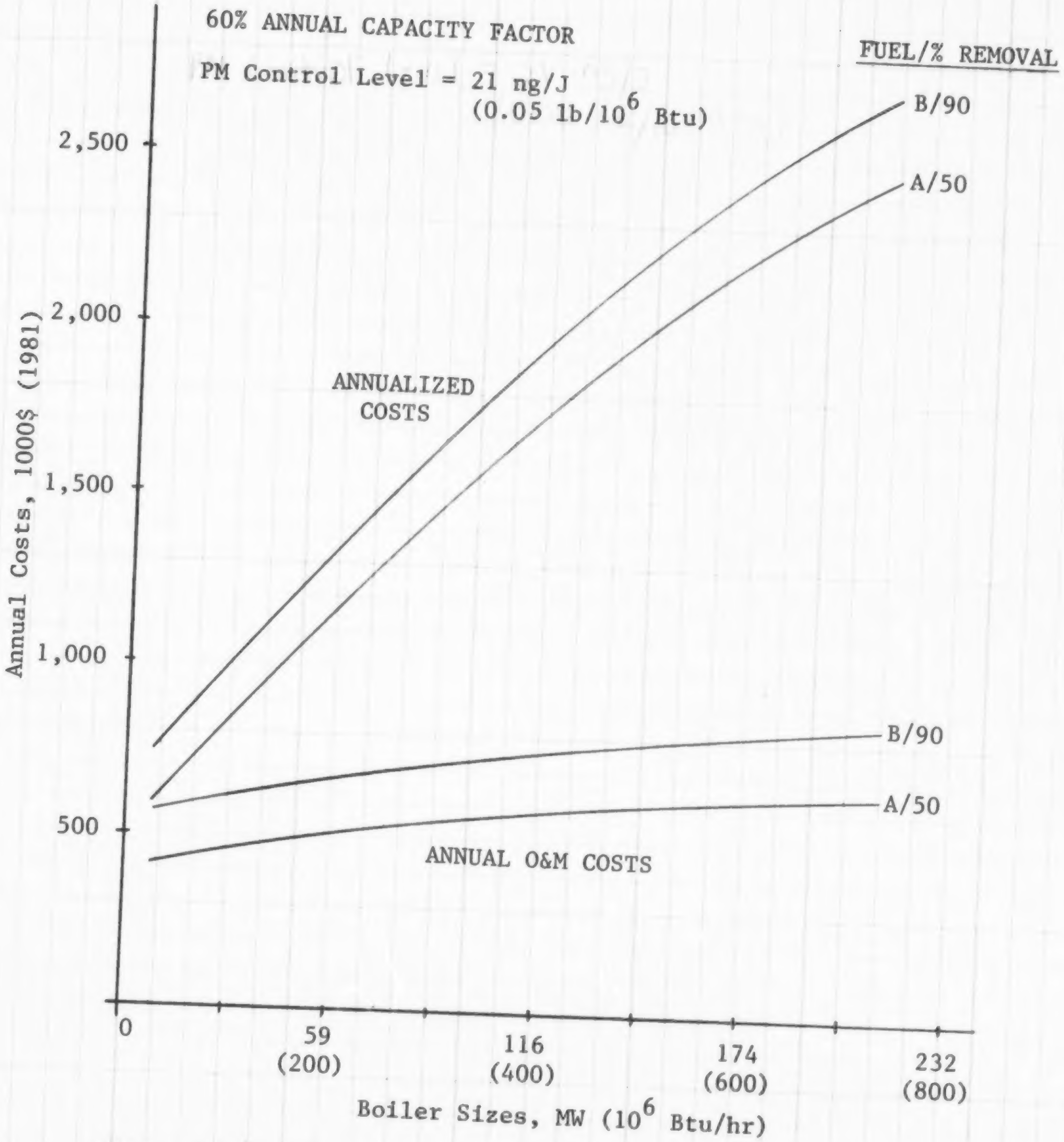
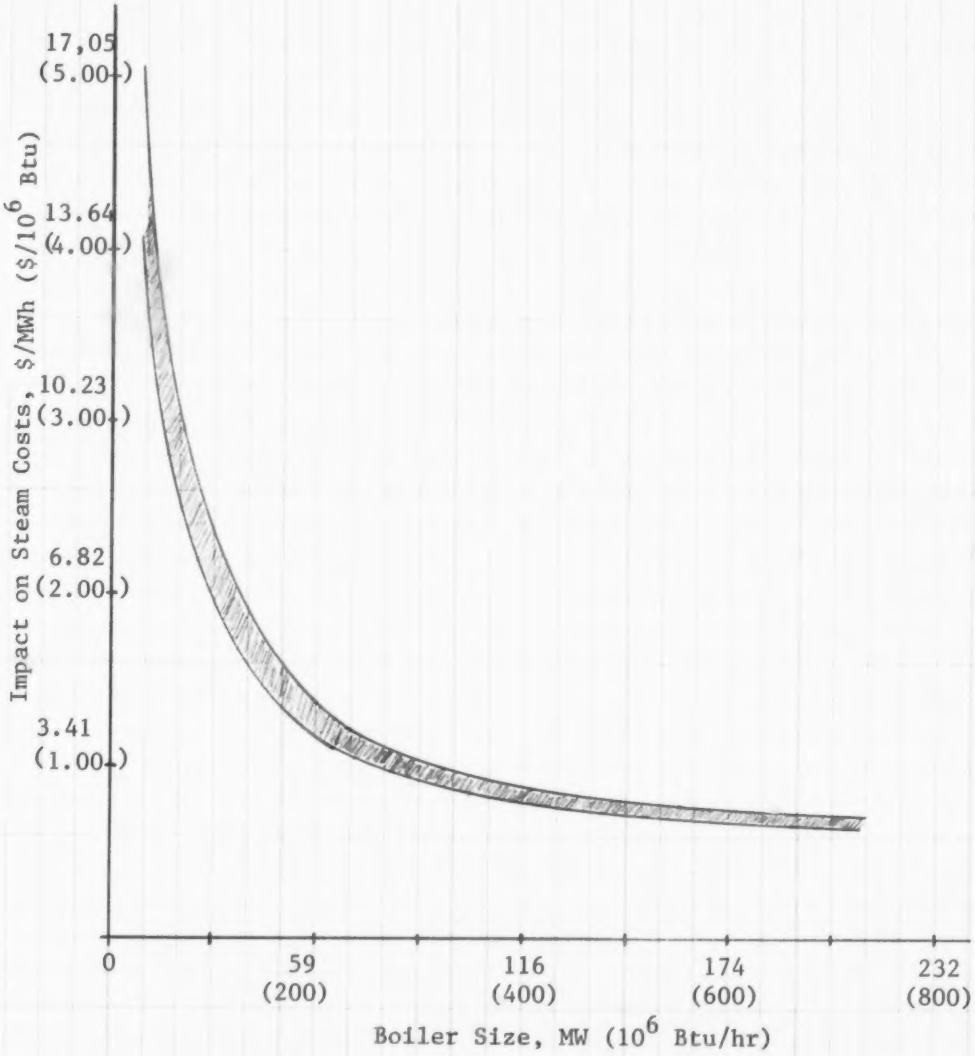


Figure 5.3-5. Annual costs of lime spray drying FGD applied to CWM boilers.



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*Heat input basis, 60 percent annual capacity factor.

Figure 5.3-6. Range of impact of lime spray drying FGD on steam costs.

uncertainty than the costs for dual alkali FGD or spray drying FGD, primarily due to the lack of large-scale facility design and operating data.

The capital costs of the dry feeders, blowers and fans were scaled down from literature estimates of dry injection costs for large coal burning power plants.[8] Fabric filter costs were based on those developed earlier in this study (Section 5.2).

As shown in Figure 5.3-7, capital costs for dry injection systems applied to 8.8 MW (30 x 10^6 Btu/hr) boiler are approximately $800,000 for all CWM fuels. For dry injection systems applied to a 205 MW (700 x 10^6 Btu/hr) boiler, capital costs range from $8,800,000 to $9,200,000. The retrofitted fabric filter costs account for 60 to 80 percent of the total dry injection system turnkey costs depending on boiler size and CWM ash content. Fabric filter costs increase with increasing boiler size and increasing CWM ash content.

5.3.3.2 Annual O&M and Annualized Costs--

The annual O&M and annualized costs for nahcolite dry injection systems are shown in Figure 5.3-8. This figure indicates several trends in the O&M and annualized costs:

- costs increase with increasing boiler size;
- costs increase with increasing sulfur content; and
- costs increase with increasing CWM ash content when CWM sulfur contents are approximately equal.

Annual O&M costs for low-sulfur fuels ("C" and "D") range from $340,000 for a 8.8 MW (30 x 10^6 Btu/hr) boiler to $1,400,000 for a 205 MW (700 x 10^6 Btu/hr) boiler. Annual O&M costs for high-sulfur, high-ash "B" fuel range from $380,000 to $2,400,000.

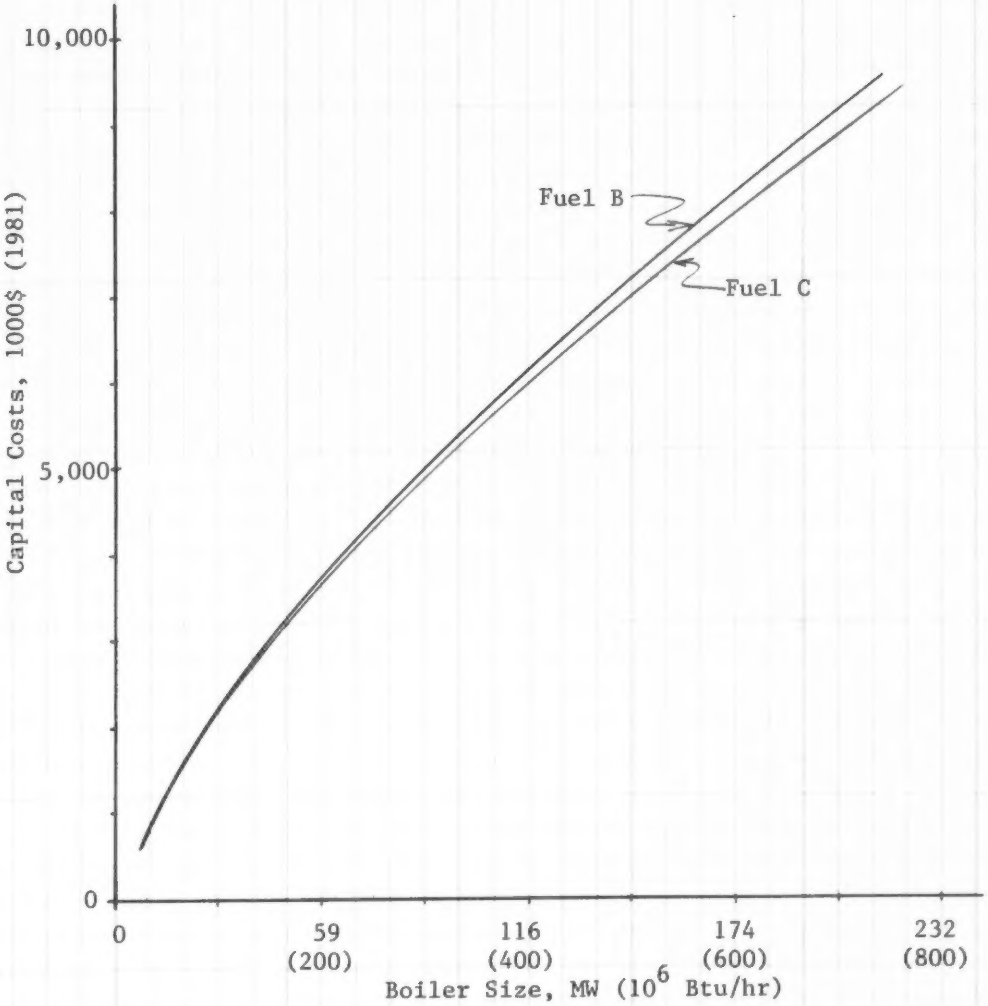

Figure 5.3-7. Capital costs of dry injection FGD for CWM boilers (fabric filter included).

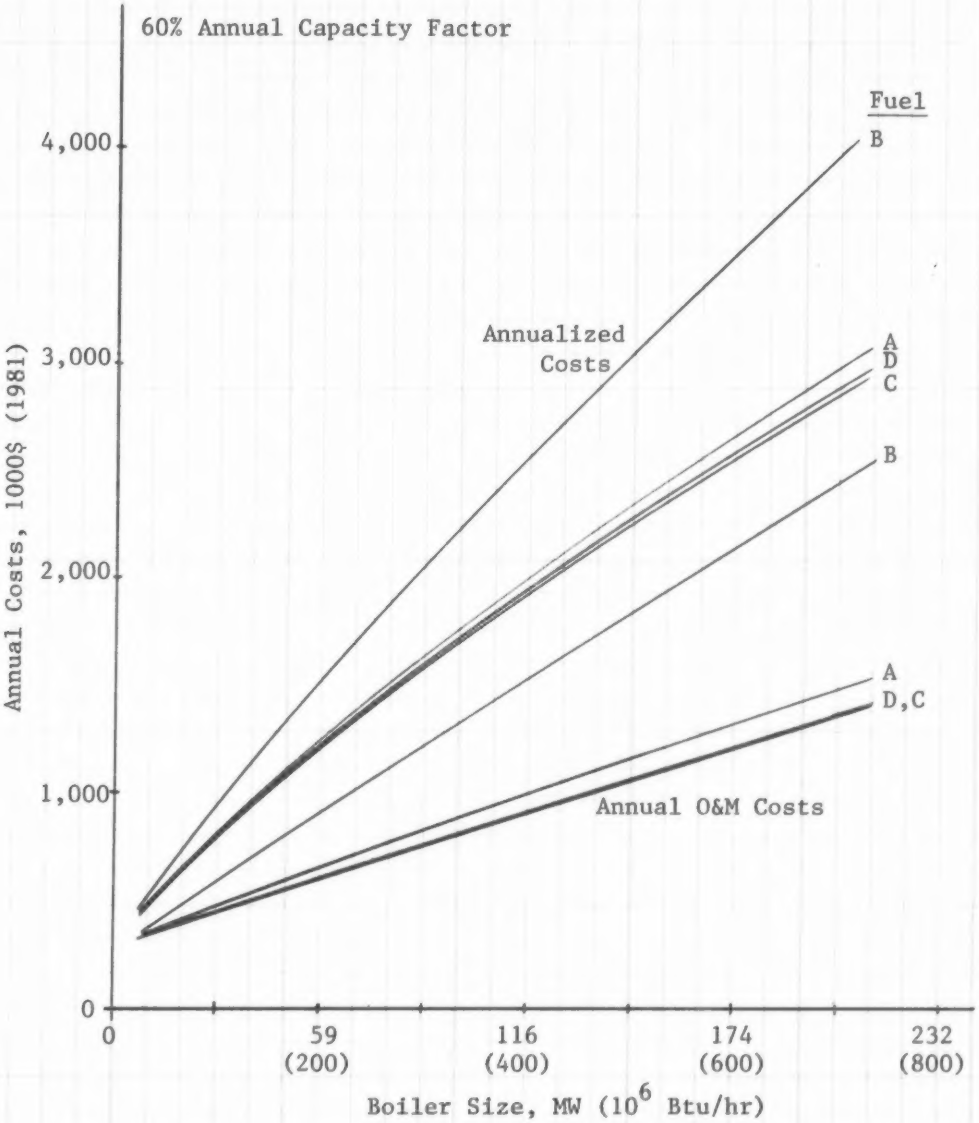

Figure 5.3-8. Annual costs of dry injection FGD applied to CWM boilers (fabric filter included).

The major components of the annual O&M costs for the dry injection system are the nahcolite and waste disposal costs, especially for the larger boiler sizes. Nahcolite costs are most significant for the higher sulfur CWMs; waste disposal costs are most significant for the higher ash CWMs.

Nahcolite costs are quite uncertain, however, because the chemical is not currently marketed.* In this study, a delivered price of $42/Mg ($38/ton) ($1978) was used to represent the cost of crushed and ground nahcolite. This price was based on data from two previous literature studies.[8,9]

The annualized costs of dry injection system applied to boilers firing "B" fuels are significantly higher than costs for "A", "C", and "D" fuels. Annualized costs are dependent on both the ash and sulfur content of the CWM fuel. Of the fuels examined, "B" has the highest ash and sulfur contents. Annualized costs for the "B" fuel range from $520,000 for a 8.8 MW (30 x 10^6 Btu/hr) boiler to almost $4,000,000 for a 205 MW (700 x 10^6 Btu/hr) boiler. Annualized costs for the remaining fuels vary from about $500,000 to $3,000,000.

5.3.4 Comparison of FGD System Costs

Figure 5.3-9 provides a comparison of the range of capital costs for the three FGD systems evaluated as a function of boiler size. For 8.8 MW (30 x 10^6 Btu/hr) boilers, dry injection and spray dryer capital costs are lower than wet FGD costs. But the capital costs of dry injection and spray drying increase faster with boiler size than do wet FGD costs, due primarily to the use of a fabric filter in the spray drying and dry injection systems. The fabric filter associated with spray drying and dry injection affords these techniques with a higher degree of PM control as well. For boilers larger than 29 MW (100 x 10^6 Btu/hr), the capital costs for wet FGD are lowest and costs for spray drying are highest.

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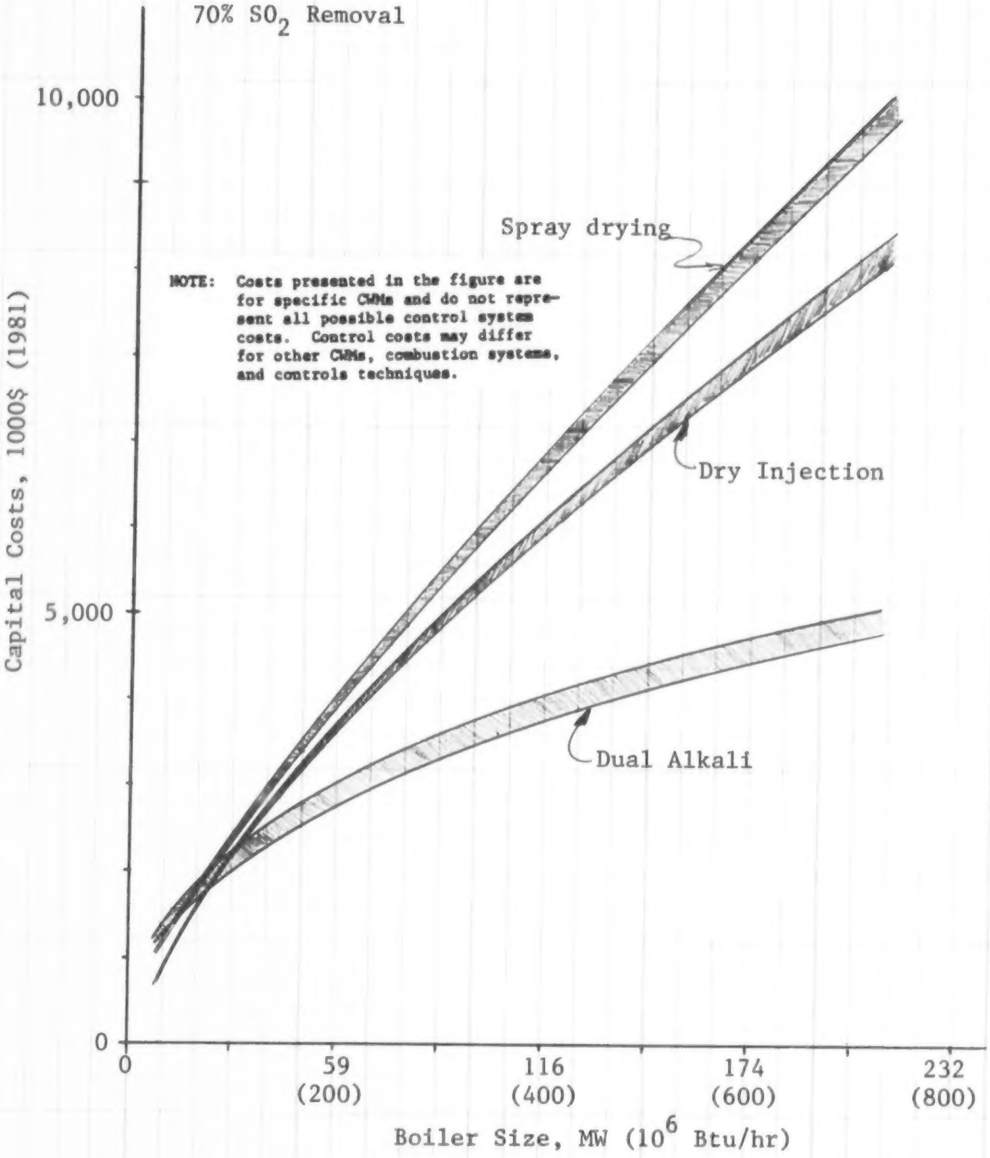
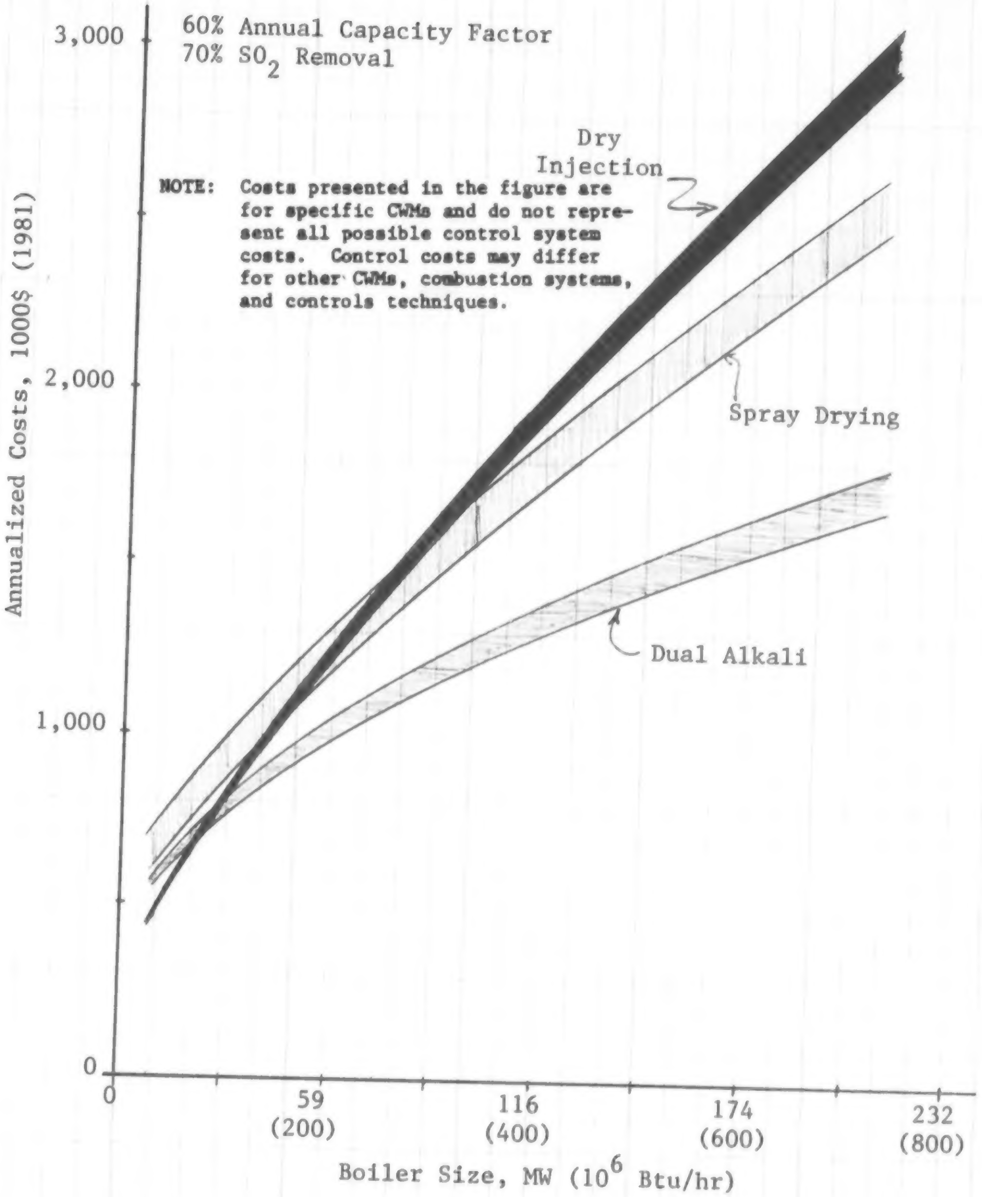
*Multiminerals Corporation is currently obtaining environmental impact data on nahcolite mining. Annual commercial production of a minimum of 1 million tons of nahcolite could be available in about 4 years.



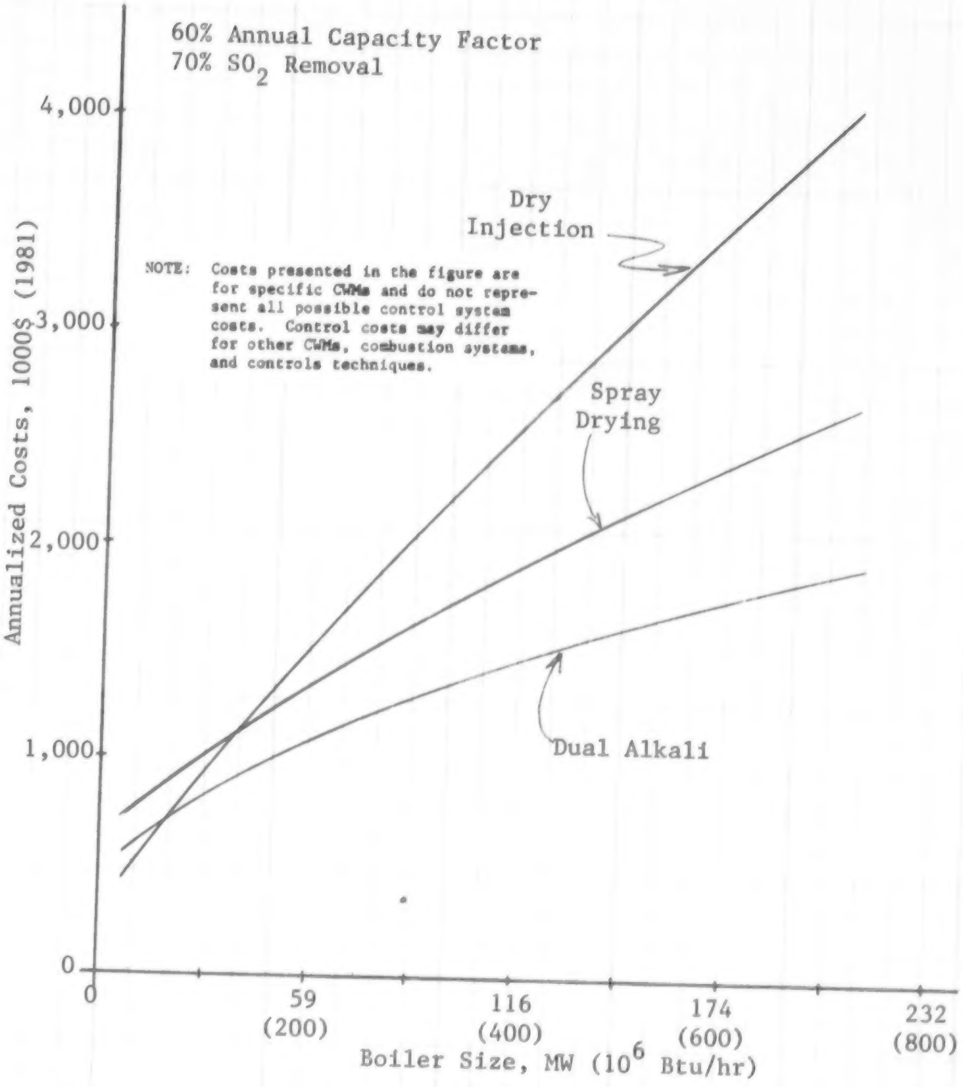
NOTE: Costs presented in the figure are for specific CWMs and do not represent all possible control system costs. Control costs may differ for other CWMs, combustion systems, and controls techniques.

Figure 5.3-9. Capital costs of three FGD systems applied to CWM boilers.



NOTE: Costs presented in the figure are for specific CWMs and do not represent all possible control system costs. Control costs may differ for other CWMs, combustion systems, and controls techniques.

Figure 5.3-10a. Annualized costs of three FGD systems applied to CWM boilers (Fuels A, C, D).



NOTE: Costs presented in the figure are for specific CWMs and do not represent all possible control system costs. Control costs may differ for other CWMs, combustion systems, and controls techniques.

Figure 5.3-10b. Annualized costs of three FGD systems applied to boilers firing a high ash, high sulfur CWM (Fuel B).

Comparisons of the annualized costs for the three FGD systems are presented in Figures 5.3-10a and b. Annualized costs for the "A", "C" and "D" fuels are given in Figure 5.3-10a. Annualized costs for "B" fuel, which are significantly higher than costs for other fuels, are given in Figure 5.3-10b. Costs for "B" fuels are highest because "B" has the highest ash and the highest sulfur contents of the CWM fuels examined.

Figures 5.3-10a and b show that dry injection will probably not be a good choice for systems firing relatively high ash and sulfur content CWM. Spray drying is more costly than wet FGD for all boiler sizes. However, spray drying FGD systems include fabric filters and may therefore be more desirable than wet FGD for boilers firing high ash CWM in terms of multi-pollutant control.

It should be noted that the comparisons presented are based on 70 percent SO_2 removal, an annual boiler capacity factor of 60 percent, and specific reagent costs. The relative costs of the three FGD systems for specific applications may be altered due to site-to-site variation in SO_2 removal, boiler capacity, reagent costs, or availability of existing equipment to reduce retrofit costs.

5.4 ANNUALIZED COST COMPARISON FOR COMBINED SO_2/PM CONTROL

The alternatives examined in the preceding sections were FGD for combined PM/SO_2 control, and fabric filters and ESPs for PM control. Two of the CWMs examined contained naturally occurring low-sulfur coals. All of the CWMs examined contained coal which had been physically cleaned. When low-sulfur coals and physically cleaned coals are used in preparing CWMs, the amount of post-combustion control required is effectively reduced.

Figure 5.4-1 presents the annualized costs (fuel costs not included) of several pollutant control schemes. The SO_2 and PM emissions levels achievable with these systems are:

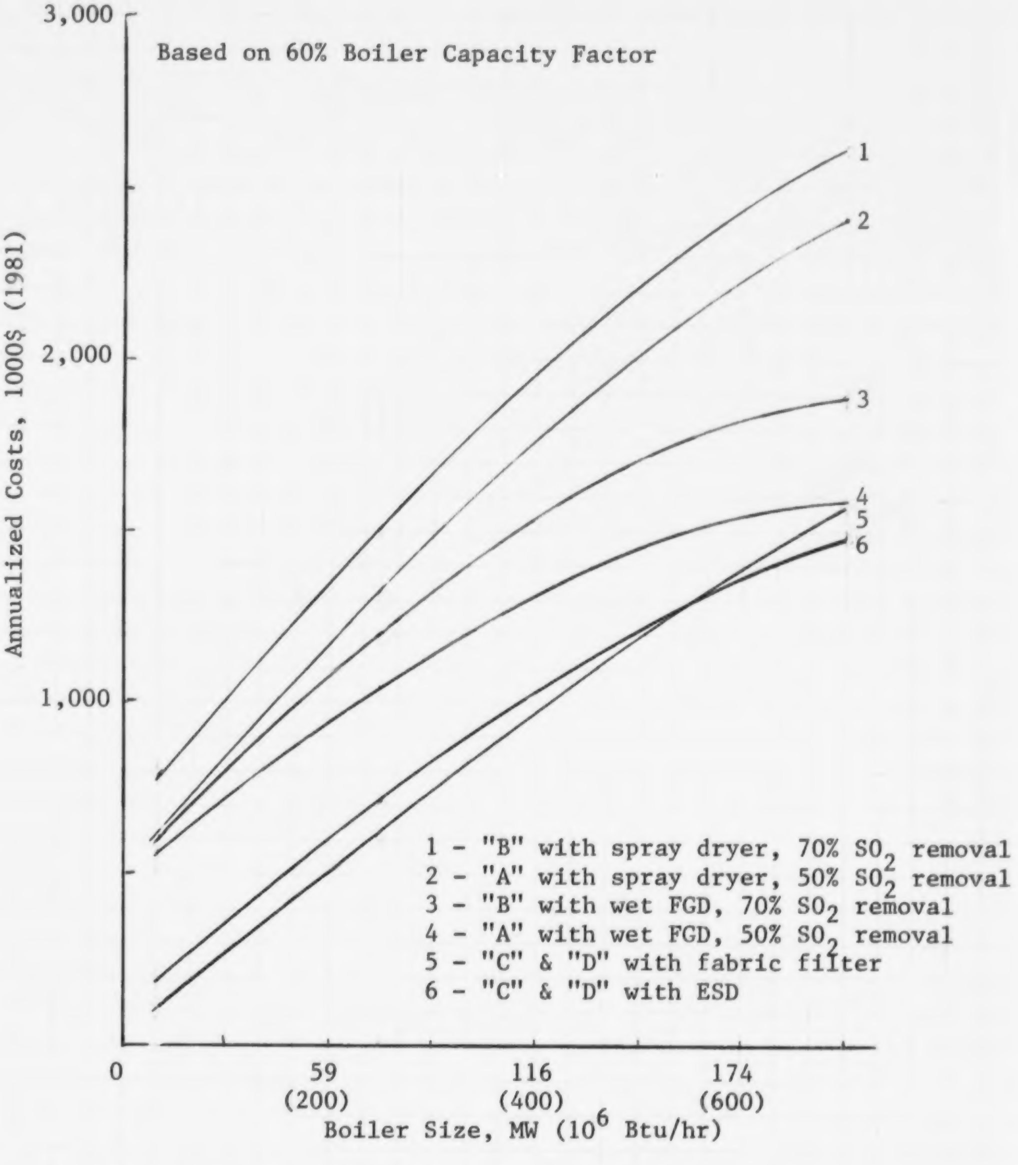


Figure 5.4-1. Comparison of annualized costs of alternatives for combined SO_2/PM control.

SO_2: nominal 520 ng/J (1.2 lb/10^6 Btu), and
PM: 21 ng/J (0.05 lb/10^6 Btu) [with dry FGD, fabric filter]
43 ng/J (0.10 lb/10^6 Btu [with ESP, wet FGD].

Figure 5.4-1 shows the effects of using CWMs prepared with low- sulfur coal as well as the effects of physical coal cleaning.

Using fabric filters or ESPs to achieve the desired SO_2 and PM emission levels on boilers firing "C" and "D" fuels results in the lowest annualized costs. The costs for controlling "A" fuels are lower than the costs for controlling "B" fuels.

However, the annualized costs presented in Figure 5.4-1 do not include fuel costs. If the prices of the CWM fuels differ substantially, the total annualized costs could be quite different from those shown in Figure 5.4-1. Table 5.4-1 shows how differing CWM prices can affect the total annualized costs. For example, if fuel "A" costs \$6/Mg (\$5/ton) more than Fuel "B", the annualized costs for purchasing Fuel "A" for a 205 MW (700 x 10^6 Btu/hr) boiler is \$920,000 more than the cost for purchasing Fuel "B". But the cost of using wet FGD to control a 205 MW (700 x 10^6 Btu/hr) boiler firing Fuel "B" is about \$300,000 more than for a boiler firing Fuel "A". Thus, the total annualized cost of burning Fuel "A" is about \$620,000 more than the cost of burning Fuel "B".

There are also other site-specific factors which might affect the relative costs of the combined SO_2/PM control alternatives shown in Figure 5.4-1. These factors include:

- local and regional labor and reagent costs,
- projected FGD system reliability,
- boiler capacity factor,
- waste disposal options and costs for FGD,
- applicable SO_2 emission standards, and

- retrofit difficulty.

5.5 NO_X CONTROL COSTS

The costs of applying combustion modification NO_x controls to boilers converted to COM is highly boiler specific. The major equipment and boiler modification requirements for the four combustion modification techniques evaluated in this study are listed below:

Technique	Major Equipment and Boiler Modification Requirements
Low excess air (LEA)	Automatic O_2 control system
Staged combustion (SC)	Automatic O_2 control system; secondary air ports if "burner out-of-service" configuration cannot be used. Modification of fuel delivery system for burners out-of-service.
Flue gas recirculation	Automatic O_2 control system; gas recirculation ductwork, increased fan capacity. Possible burner and windbox modifications.
Low-NO_x burners	New burners; automatic O_2 control system.

In addition to the costs for equipment and boiler modifications, there are capital costs associated with boiler derating, since additional capacity may be required as a result of the derating, and increased operating costs, due

TABLE 5.4-1. ANNUALIZED FUEL COST DIFFERENTIALS FOR CWMs[a]

Boiler Size-MW (10^6 Btu/hr)	CWM Price Differential		
	$6/Mg ($5/ton)	$11/Mg ($10/ton)	$22/Mg ($20/ton)
8.8 (30)	39,000	79,000	158,000
73 (250)	329,000	657,000	1,314,000
205 (700)	920,000	1,840,000	3,679,000

[a] Assuming a 60 percent boiler annual capacity factor and CWM heating value of 23,300 kJ/kg (10,000 Btu/lb).

to a slight loss in efficiency that accompanies these combustion modification techniques. For retrofit applications, the costs of installing the new equipment or modifying the boiler will depend strongly on the existing boiler design. All of these NO_x reduction techniques require automatic O_2 control systems which cost about $10,000 (uninstalled, $1981).

5.6 CWM FUEL COSTS

There are several factors which directly impact the cost of CWM fuels. These factors include:

- coal beneficiation costs,
- CWM preparation costs, and
- coal/CWM transportation costs.

This section provides a brief summary of these costs. More detailed cost estimates may be found in Appendix A.

5.6.1 Coal Beneficiation Costs

The beneficiation of coal by physical coal cleaning techniques decreases the ash and sulfur contents, and improves the heating value of the cleaned coal product. The costs associated with physical coal cleaning include those related to cleaning plant capital, operation and maintenance, and the loss of Btu content in the raw coal eliminated as refuse. The cost factors per Mg (ton) of cleaned coal are listed in Table 5.6-1.

Capital charges and operating charges increase with increasing degree of coal beneficiation. And the yield of cleaned coal product decreases with increasing degree of coal beneficiation (i.e. at higher levels of cleaning, more coal and available heating value is lost to refuse). Thus, as higher levels of cleaning are used, the total costs associated with coal

TABLE 5.6-1. COST FACTORS PER TON OF BENEFICIATED COAL[10]

$$\text{Amortization} = \frac{\text{cleaning plant yearly amortization cost}}{\text{Mg (tons) of clean coal per year}}$$

Operation and Maintenance = based on various cost components, plant yield, current and historical cost values and escalation factors

Value of raw coal sent to refuse = raw coal value (1 - yield (decimal value) per Mg (ton)

$$\text{Tax and insurance} = \frac{\text{yearly tax and insurance burden}}{\text{Mg (tons) of clean coal per year}}$$

beneficiation increase. Table 5.6-2 presents typical costs for various coals and levels of cleaning. A more detailed discussion of these costs is included in Appendix A. Coal beneficiation costs presented in this study were derived from data and information in Reference 11. Table 5.6-2 shows that the cost of coal lost to refuse is a major contributor to the total cost, especially at the higher levels of cleaning. The total cleaning costs range from about \$2.2/Mg (\$2.00/ton) of cleaned coal for the lower levels of cleaning to about \$13.75/Mg (\$12.50/ton) for the higher levels of cleaning.

5.6.2 CWM Preparation Costs

The costs associated with preparing a coal-water mixture for use as a boiler fuel are presented in this section. The actual costs of CWM preparation should be about equal for all types of coal. Therefore, the cost of the CWM product will reflect the price of the coal used to prepare it in addition to the preparation costs. Figure 5.6-1 presents the cost of prepared CWM on a heating value basis as a function of the parent coal price. The costs shown in Figure 5.6-1 were developed using costs presented in Reference 12. The cost of the CWM shown does not include profit to the CWM preparer nor does it include the cost of transporting the CWM to the boiler site. The cost of the parent coal is the cost of the coal delivered (including transportation) to the CWM preparation facility. Assumptions and bases used in determining CWM preparation costs are detailed in Appendix A. These costs agree with other estimates predicting CWM costs of \$10.23 to \$11.94 MWh (\$3.00 to \$3.50/10^6 Btu).[13]

CWMs typically have higher heating values ranging from about 16 J/kg (7,000 Btu/lb) to 23 J/kg (10,000 Btu/lb). Coal having a heating value of 23 J/kg (10,000 Btu/lb) would produce a CWM with a heating value of 16 J/kg (7,000 Btu/lb). Coal with a heating value of about 33 J/kg (14,300 Btu/lb) would produce a CWM with heating value of 23 J/kg (10,000 Btu/lb).

TABLE 5.6-2. COAL BENEFICIATION[2]

Coal Type	Level of Cleaning	Annualized Cost ($/mg[$/ton] of cleaned coal)	Cost of Refuse Lost[c,d] ($/mg[$/ton] of cleaned coal)	Total ($/mg[$/ton] of cleaned coal)
HSE	5	3.85 (3.50) - 4.68 (4.25)	9.16 (8.33)	13.01 (11.83) - 13.84 (12.58)
HSE	3-4	2.24 (2.20) - 2.86 (2.60)	4.9 (4.41)	7.27 (6.61) - 7.71 (7.01)
LSE	2	1.43 (1.30) - 1.54 (1.40)	2.20 (2.00)	3.36 (3.30) - 3.74 (3.40)
LSW	2	1.43 (1.30) - 1.54 (1.40)	.69 (0.63)	2.12 (1.93) - 2.23 (2.03)

[a] End-1981 costs based on a cleaning facility located at mine mouth which processes 1.8 x 10^6 Mg (2 x 10^6 tons) of ROM coal per year. See Appendix B for other assumptions and bases.

[b] The range of costs depicts annualized costs without dewatering (low end) and with dewatering (high end). See Section 4.2.1 and Appendix B for discussion.

[c] Assuming 95 percent yield for Level 2, 85 percent yield for Level 3, and 75 percent yield for Level 5 cleaning.

[d] Assuming coal costs: HSE - $28/Mg ($25/ton)
LWE - $42/Mg ($38/ton)
LSW - $13/Mg ($12/ton)

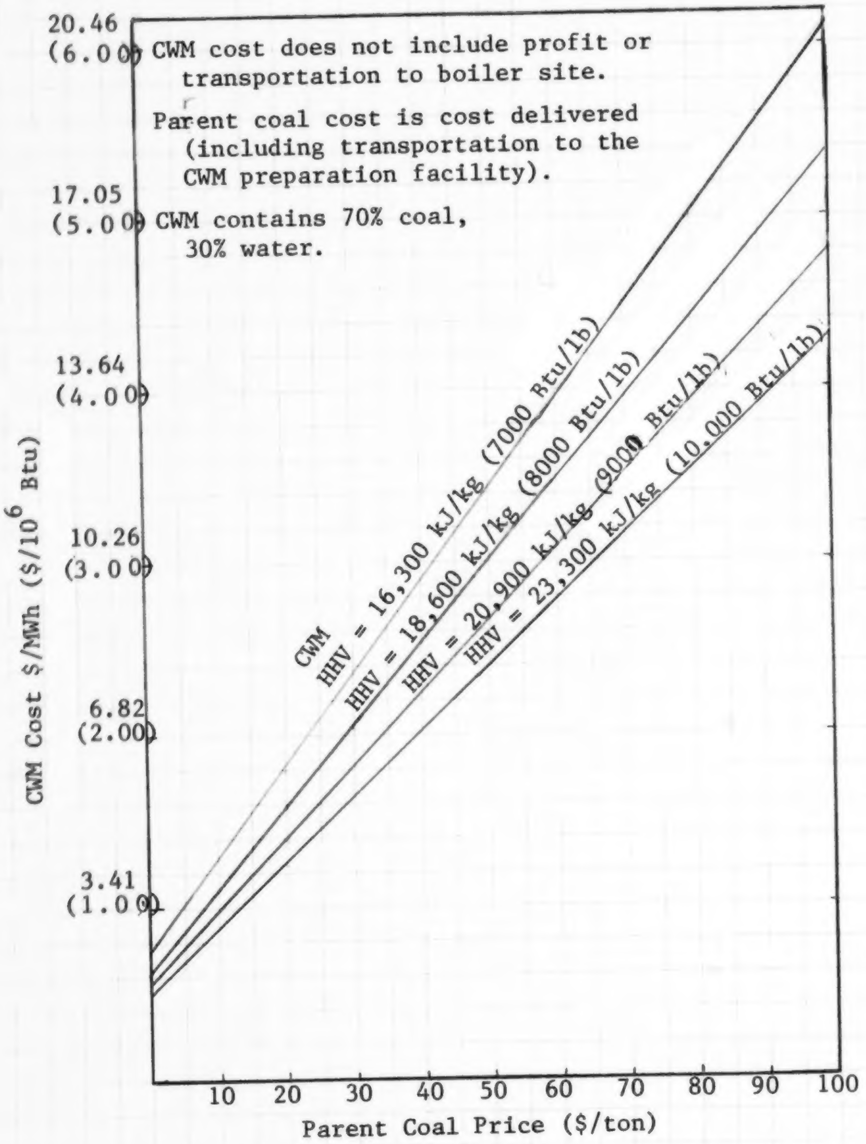


Figure 5.6-1. Cost of prepared CWM.

5.6.3 Transportation Costs

Transportation costs can have a significant effect on CWM cost, especially if the boiler site is located far from the CWM preparation facility, or the CWM preparation facility is located far from the mine site. Most CWM preparation facilities are expected to be located in the Eastern United States, so that the use of CWM fuels in the West may not be economically favorable. The distance between the CWM preparation facility and mine site also affects CWM cost because the CWM producer must pay the cost for transporting coal to his facility. These transportation costs are then reflected in the price of the CWM product. To remain competitive, a CWM producer will have to produce a high quality product at a low price. Due to the high costs associated with transporting low- sulfur western coal to the East, it may be more economical to produce CWMs from highly beneficiated Eastern coals.

Cleaned coal is transported wet or dry from the mine site to the CWM preparation facility via rail or barge. The CWM product is then transported as a liquid fuel via rail, barge, or slurry pipeline to the boiler site.

CHAPTER 5 REFERENCES

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APPENDIX A

This Appendix contains information used in developing the emission control, coal beneficiation, and CWM preparation costs presented in Chapter 5.

Section A.1 deals with boiler-related parameters impacting the control costs. Section A.2 presents the emission control equipment specifications used to develop control costs. Section A.3 provides documentation of the unit costs used to calculate labor, electricity, chemicals, maintenance and waste disposal costs. Detailed equations used to calculate the new system costs ($1978) (except for dry injection) can be found in Reference A-1. Dry injection costs were based on information in Reference A-2.

Section B.4 deals with bases and data used to calculate coal beneficiation costs. The costs presented in this study were based on costs found in References A-5 and A-6. Section A.5 discusses the bases for CWM preparation costs. These costs were based on information in Reference A-7.

A-1. BOILER RELATED PARAMETERS

Table A-1 shows the hypothetical ultimate analysis of the CWM fuels used in this study. Based on an excess air level of 35 percent, the following flue gas flows were calculated:

CWM Fuel	Gas Flow @ 200°C (400°F) [actual ft^3/Btu of Fuel Burned]
A	0.0216
B	0.0218
C	0.0217
D	0.0225

TABLE A-1. ULTIMATE ANALYSIS OF CWM FUELS

Fuel	Moisture	Composition - Wt. %					
		Carbon	Hydrogen	Nitrogen	Oxygen	Sulfur	Ash
A High-Sulfur Eastern Level 5 Cleaning	30	56.11	3.84	1.1	7.7	0.81	2.4
B High-Sulfur Eastern Levels 3 & 4 Cleaning	30	52.9	3.6	1.1	5.4	1.5	5.6
C Low-Sulfur Eastern Level 2 Cleaning	30	57.0	3.4	1.1	3.5	0.56	4.4
D Low-Sulfur Western Level 2 Cleaning	30	51.3	2.8	1.1	10.0	0.46	4.3

*HHV = higher heating value

Thus, for the boiler sizes examined flue gas flows to be treated were approximately:

8.8 MW (30 x 10^6 Btu/hr) -- 11,000 acfm (5.2 m^3/sec)

73 MW (250 x 10^6 Btu/hr) -- 91,000 acfm (43.0 m^3/sec)

205 MW (700 x 10^6 Btu/hr) -- 256,000 acfm (121 m^3/sec)

The boiler sizes selected for evaluation are representative of the sizes of boilers which might be converted to CWM. It is very unlikely that any boilers smaller than 8.8 MW (30 x 10^6 Btu/hr) will be converted to CWM. A boiler size of 73 MW (250 x 10^6 Btu/hr) represents the mid-size range of industrial boilers. Also, boilers with heat inputs of 73 MW (250 x 10^6 Btu/hr) or larger are considered major sources for many environmental regulations. A boiler size of 205 MW (700 x 10^6 Btu/hr) represents the upper end of industrial boiler sizes and an average size for utility boilers.

A.2 CONTROL EQUIPMENT SPECIFICATIONS

Tables A-2 through A-6 present the specifications for the following emission control equipment:

- Electrostatic Precipitator (PM);
- Fabric Filter (PM);
- Dual Alkali venturi scrubber (PM/SO_2);
- Spray drying (PM/SO_2); and
- Dry injection (PM/SO_2).

A.3 UNIT COSTS

Table A-7 presents the unit costs for utilities, chemicals, labor, disposal). The 1981 costs shown in Table A-7 were updated from 1978 costs using a factor of 1.4 based on the CE Plant Index (Reference A-3).

TABLE A-2. ELECTROSTATIC PRECIPITATOR EQUIPMENT SPECIFICATIONS

Equipment Description:	Cold-side ESP containing compartmented electrical units cleaned by mechanical rappers
Cost Analysis Includes:	Fan and damper, ducting; ESP plates, wires, rappers, transformers, rectifiers and controls, ESP chamber
Specifications:	Specific collection area (SCA)[a] = 59 $m^2/(m^3/sec)$(300 ft^2/1000 acfm) for Fuels A and B 69 $m^2/(m^3/sec)$(350 ft^2/1000 acfm) for Fuels C and D System pressure drop = 0.13 kPa (0.5 inches water column) Induced draft fan Design gas velocity = 1.5 to 1.8 m/s (5 to 6 ft/s) Ductwork - 61 m (200 ft) long

[a] Reference A-4.

TABLE A-3. FABRIC FILTER EQUIPMENT SPECIFICATIONS

Equipment Description:	Compartmented modules cleaned by reversing the air flow
Cost Analysis Includes:	Fan and damper, ducting, filter bags, steel structural supports, and controls
Specifications:	Air-to-cloth ratio (A/C) = 2/1 Pressure drop = 1.5 kPa (6" water column) Bags - Teflon coated fiberglass with a 2 year life Induced draft fan Ductwork - 61 meters (200 ft) long

TABLE A-4. DUAL ALKALI/VENTURI SCRUBBER EQUIPMENT SPECIFICATION

Equipment Description:	Variable-throat venturi SO_2 absorber, and sodium sorbent recovery reactor. Scrubber preceeded by mechanical collector.
Cost Analysis Includes:	Raw materials handling and preparation, venturi scrubber, mechanical collector, reactor, clarifier, vacuum filter, holding tanks, pumps, fan, pipe, ductwork and controls.
Specifications:	Gas pressure drop = 5kPa (20" H_2O) L/G = 1.3 l/m^3 (10 gal/1000 ft^3) Scrubber liquor = 5% dissolved solids by weight Scrubber liquor pH = 6 to 8 Stainless steel construction Scrubber sludge = 60% solids

TABLE A-5. LIME SPRAY DRYER EQUIPMENT SPECIFICATIONS

Equipment Description:	Spray dryer and fabric filter system
Cost analysis includes:	Spray dryer, fabric filter, fan, ductwork, sorbent preparation and handling equipment, pumps and pipes (fabric filter specifications in Table B-2).
Specifications:	L/G = 0.04 l/m^3 (0.3 gal/1000 ft^3) Gas pressure drop = 1.5 kPa (6" H_2O) Flue gas residence time = 10 seconds Spray dryer outlet temperature = 80°C (175°F)

TABLE A-6. DRY INJECTION EQUIPMENT SPECIFICATIONS

Equipment Description:	Pneumatic sorbent injection and fabric filter system.
Cost analysis system:	Baghouse and auxiliaries, induced draft fans, 2 sorbent hoppers, sorbent conveyor, 4 rotary feeders and 2 blowers.
Specifications:	Baghouse operated for 72 minutes between cleanings.
	Filter bags are precoated with 20% of the total required nahcolite feed.
	Nahcolite was assumed to contain 70% $NaHCO_3$.

TABLE A-7. UNIT COSTS USED IN CALCULATIONS[a]

Utilities	
Electricity	\$0.0361/kWh
Water	\$0.06/m^3 (\$0.21/10^3 gal)
Steam	\$4.21/GJ (\$4.9/10^3 lb)
Raw Material	
Na_2CO_3	\$0.139/kg (\$126/ton)
Lime	\$0.055/kg (\$49/ton)
Limestone	\$0.013/kg (\$11/ton)
Nahcolite	\$0.059/kg (\$53/ton)
Labor	
Direct Labor	\$16.83/man-hour
Supervision	\$21.88/man-hour
Maintenance Labor	\$20.48/man-hour
Waste Disposal (Off-Site Landfill)	
Solids (Ash, Spray Dried Solids)	\$0.023/kg (\$21/ton)
Sludge	\$0.023/kg (\$21/ton)

[a] All costs in 1981 \$.

A.4 COAL BENEFICIATION COSTS

All coal beneficiation costs were based on a cleaning facility designed to handle 2 million tons of raw coal per year. Costs for the various levels of cleaning were taken from Reference A-5.

As discussed in Section 4.2, cleaned coal to be used in preparing CWM may not require dewatering. Examining the equipment and power costs given in Reference A-5, it was observed that the equipment and power costs associated with dewatering were substantial. Estimated cost reductions achieved by elimininating dewatering operations are shown in Table A-8.

TABLE A-8. COST REDUCTIONS ACHIEVED BY NOT DEWATERING CLEANED COAL

Level of Cleaning	Equipment Cost Reduction (%)	Power Cost Reduction (%)
5	50	30
3 & 4	40	28
2	30	25

No charges were made to the other costs (labor, land, waste disposal, chemicals, etc.). Table A-9 presents the 1981 costs for various levels of coal cleaning. These costs were updated from 1978 costs given in Reference A-5 using a factor of 1.4 (Reference A-3).

In determining the beneficiation cost per ton of cleaned coal (as presented in Table 5.6-2), the quantity of coal lost to refuse or the yield of clean coal from raw coal must be established.

TABLE A-9. COAL BENEFICIATION COSTS FOR VARIOUS LEVELS OF CLEANING[a]
$ 1000 (1981)

Level of Cleaning	Dewatering Costs Included	Dewatering Costs Excluded
5		
Total Capital Cost	$ 25,372	$ 19,194
Annualized Cost[b]	8,890	7,279
3 & 4		
Total Capital Cost	14,556	10,790
Annualized Cost[b]	6,132	5,229
2		
Total Capital Cost	7,119	6,124
Annualized Cost	3,678	3,496

[a] Coal cleaning facility processes 1.8 x 10^6 Mg (2 x 10^6 tons) of raw coal per year.

[b] Excluding raw coal costs.

For the purposes of this study, a 75 weight percent recovery was assumed for Level 5 cleaning, 85 percent for Levels 3 and 4, and 95 percent for Level 2. The raw coal costs assumed for this study were based on prices from Reference A-6:

High-Sulfur Eastern	--	\$25/ton,
Low-Sulfur Eastern	--	\$38/ton, and
Low-Sulfur Western	--	\$12/ton.

A.5 CWM PREPARATION COSTS

CWM preparation costs presented in this study were developed using costs presented in Reference A-7. Costs were based on a facility which processed 4.5×10^6 Mg (5×10^6 tons) coal per year to produce 6.0×10^6 Mg (6.6×10^6 tons) CWM per year. Direct costs, land costs, and O&M costs, were taken directly from Reference A-7 and updated from \$1980 to \$1981. Indirect costs, contingencies, overhead, working capital, capital recovery, taxes, and insurance were computed based on capital costs so as to be consistent with the cost methodology used throughout this study. For the particular CWM facility evaluated here, the following costs (\$ end-1981) were developed:

Total Capital = \$116,900,000
Annualized = \$65,800,000 (excluding coal cost).

These are CWM preparation costs and do not vary significantly for differing coal types. To determine the total CWM preparation costs (excluding profit to the CWM producer and transportation costs) the cost of the coal to the CWM producer must be added to the annualized preparation costs. Coal costs incurred by the CWM producer will reflect not only coal type, but also cleaning and transportation costs.

A.6 REFERENCES

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APPENDIX B

ABBREVIATIONS

AA	Atomic absorption
BOOS	Burners out of service
CAA	Clean Air Act
CFR	Capital Recovery Factor
CLM	Coal-liquid mixture(s)
COM	Coal-oil mixture)(s)
COW	Coal-oil-water mixture(s)
CWM	Coal-water mixture(s)
DOE	U. S. Department of Energy
EPA	U. S. Environmental Protection Agency
EPRI	Electric Power Research Institute
ESP	Electrostatic precipitator
FGD	Flue gas desulfurization
FGR	Flue gas recirulcation
FGT	Flue gas treatment
HHV	Higher heat value
HSE	High Sulfur Eastern
LEA	Low excess air
L/G	Liquid-to-gas ratio
LSE	Low Sulfur Eastern
LSW	Low Sulfur Western
MSHA	Mine Safety and Health Administration
MW	Megawatt
NA	Nonattainment
NAA	Neutron Activation Analysis
NAAQS	National Ambient Air Quality Standards
NH_3	Ammonia
NO_x	Nitrogen Oxides
NPDES	National Pollution Discharge Elimination System
NSPS	New Source Performance Standards
O&M	Operation and Maintenance
OFA	Overfire air
OSHA	Occupational Safety and Health Administration

PETC	Pittsburgh Energy Technology Center
PCC	Physical coal cleaning
PM	Particulate matter
POM	Polynuclear Organic Material
PSD	Prevention of significant deterioration
ROM	Run-of-mine
SC	Staged combustion
SCR	Selective catalytic reduction
SIP	State Implementation Plan
SO_2	Sulfur Dioxide

APPENDIX C

CONVERSION FACTORS

ENGLISH AND METRIC UNITS TO SI UNITS

To Convert From	TO	MULTIPLY BY
in	cm	2.540
in^2	cm^2	6.452
ft	m	0.3048
ft^2	m^2	0.09290
lb	kg	0.4536
lb/hr	Mg/s	0.1260
$lb/10^6$ Btu	ng/J	430
g/Mcal	ng/J	239
Btu	J	1054
Btu/lb	J/kg	0.002324
Btu/hr	W	0.2929
J/sec	W	1.000
J/hr	W	3600
Btu/ft/hr	W/m	0.9609
Btu/ft/hr	J/hr/m	3459
$Btu/ft^2/hr$	W/m^2	3.152
$Btu/ft^2/hr$	$J/hr/m^2$	11349
$Btu/ft^3/hr$	W/m^3	10.34
$Btu/ft^3/hr$	$J/hr/m^3$	37234
psia	Pa	6895
"H_2O	Pa	249.1
Rankine	Celsius	C = 5/9R-273
Fahrenheit	Celsius	C = 5/9(F-32)
Celsius	Kelvin	K = C+273
Rankine	Kelvin	K = 5/9R
COAL FUEL ONLY		
ppm @ 3% O_2 (SO_2)	ng/J	0.851
ppm @ 3% O_2 (SO_3)	ng/J	1.063
ppm @ 3% O_2 (NO)	ng/J	0.399
ppm @ 3% O_2 (NO_2)	ng/J	0.611
ppm @ 3% O_2 (CO)	ng/J	0.372
ppm @ 3% O_2 (CH_4)	ng/J	0.213

SI UNITS TO ENGLISH AND METRIC UNITS

To Convert From	To	Multiply By
cm	in	0.3937
cm^2	in^2	0.1550
m	ft	3.281
m^3	ft^3	35.315
kg	lb	2.205
Mg/s	lb/hr	7.937
ng/J	$lb/10^6$ Btu	0.00233
ng/J	g/Mcal	0.00418
J	Btu	0.000948
J/kg	Btu/lb	4.303
J/hr/m	Btu/ft/hr	0.000289
$J/hr/m^2$	$Btu/ft^2/hr$	0.0000881
$J/hr/m^3$	$Btu/ft^3/hr$	0.0000269
W	Btu/hr	3.414
W	J/hr	0.000278
W/m	Btu/ft/hr	1.041
W/m^2	$Btu/ft^2/hr$	0.317
W/m^3	$Btu/ft^3/hr$	0.967
Pa	psia	0.000145
Pa	"H_2O	0.004014
Kelvin	Fahrenheit	F = 1.8k-460
Celsius	Fahrenheit	F = 1.8C+32
Fahrenheit	Rankine	R = F+460
Kelvin	Rankine	R = 1.8k

COAL FUEL ONLY

To Convert From	To	Multiply By
ng/J	ppm @ 3% O_2 (SO_2)	1.18
ng/J	ppm @ 3% O_2 (SO_3)	0.941
ng/J	ppm @ 3% O_2 (NO)	2.51
ng/J	ppm @ 3% O_2 (NO_2)	1.64
ng/J	ppm @ 3% O_2 (CO)	2.69
ng/J	ppm @ 3% O_2 (CH_4)	4.69

SI PREFIXES

Multiplication Factor	Prefix	SI Symbol
10^{12}	tera	T
10^{9}	giga	G
10^{6}	mega	M
10^{3}	kilo	k
10^{2}	hecto*	h
10^{1}	deka*	da
10^{-1}	deci*	d
10^{-2}	centi*	c
10^{-3}	milli	m
10^{-6}	micro	m
10^{-9}	nano	n
10^{12}	pico	p
10^{15}	femto	f
10^{18}	atto	a

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*Not recommended but occasionally used.